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# Joint Long-Range Energy Study for Greater Fairbanks Military Complex

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Final Report



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**Abstract:** This study evaluated onsite and regional options for providing heat and power to Fort Wainwright, Eielson Air Force Base, Fort Greely, and the Ground-Based Midcourse Defense installation adjacent to Fort Greely, collectively known as the Greater Fairbanks Military Complex (GFMC). The alternatives evaluated include site-specific alternatives (continued operation of existing plant and new plant) and regional alternatives to provide power or both heat and power. The report provides background information on the energy supply situation in Interior Alaska, the availability of fuels, and the existing energy infrastructure and reviews the suitability of possible technologies for long-term heat and power solutions for the GFMC installations. The report also develops evaluation criteria for fuels and alternative heat and power solutions. Life-cycle costs are developed for each alternative and are used in the evaluation along with other criteria such as security, impact on Alaska infrastructure, and air and water quality. Results of the analysis are presented to allow the Department of Defense to make an informed decision about heat and power solutions for the installations.

# Executive Summary

In May 2003, the Assistant Chief of Staff for Installation Management (ACSIM) requested that the U.S. Army Engineer Research and Development Center (ERDC), Construction Engineering Research Laboratory (CERL) conduct a Joint Long-Range Energy Study for Fort Wainwright (FWA), Fort Greely (FGA), the Ground-Based Midcourse Defense (GMD) installation adjacent to FGA, and Eielson Air Force Base (EAFB), collectively referred to as the Greater Fairbanks Military Complex (GFMC). ERDC awarded a contract to CH2M HILL in August 2003 to perform the technical study.

The goal of this joint study was to assess the options for long-range regional heat and power in the GFMC area and provide recommended courses of action to achieve environmentally responsible, reliable, and economically viable heat and electric power based on a 25-year period. This study provides the Services (U.S. Army and U.S. Air Force) and the Missile Defense Agency (MDA) with recommendations on regional and installation-specific approaches to the provision of heat and power supply for the GFMC installations.

The tasks for achieving the objectives of the study included (1) the evaluation of fuel options and regional and installation-specific alternatives for heat and power supply, and (2) a review of possible power-generating technologies, including renewable resources. The evaluation was done independently of specific ownership considerations. The following alternatives for providing heat and electric power to the GFMC were evaluated:

- **Regional Electric Power Plant.** This alternative involves building a regional electric power plant to meet the mission-required electricity needs of the installations over and above the electricity generation at the existing FWA and EAFB Central Heat and Power Plants (CHPPs), which is produced as a by-product of heat production. The plant could be either coal- or oil-fired.
- **Regional Heat and Electric Power Plant.** This alternative involves building a regional CHPP to meet the combined heating demands of FWA and EAFB and the mission-required electricity needs of all of the installations. The plant would most likely be located on EAFB to avoid the Fairbanks carbon monoxide (CO) management/non-attainment area (NAA). This solution would require the construction of

a long-distance heat transmission system to FWA and to interconnect to the existing EAFB system. Similar to the regional electric power plant, a regional CHPP could be either coal- or oil-fired.

- **Repair.** This alternative involves building continuing operation of the existing CHPPs, accomplishing appropriate repairs, and buying additional power needs from Golden Valley Electric Association (GVEA). In this alternative, steam is produced to meet heating load, and additional steam is generated specifically to produce electricity, but only to the limit of the existing CHPP design capacity.
- **Repair and Upgrade**. This alternative is similar to the Repair alternative except that additional new electrical generation capacity is added to the CHPPs to meet future electricity demands. This alternative minimizes or eliminates electricity purchases from GVEA even as demand at the military installations increases.
- **Repair, Using Electricity Produced by "Following the Heat Curve."** This alternative is similar to the Repair alternative except that electricity generation would be based on heat loads only. Unlike the Repair and Repair and Upgrade alternatives, no steam would be produced solely for electric power generation beyond what is needed to meet heating loads.
- **Upgrade Coal-Fired Boilers with New Circulating Fluidized-Bed Boilers (CFBs).** EAFB anticipates replacing two current boilers with two new boilers. This alternative was evaluated for EAFB only; FWA does not have similar plans.
- **New Coal-Fired CHPP.** This alternative involves building a new standalone CHPP to meet the projected installation heat and electricity needs.
- **New Oil- or Gas-Fired CHPP.** This alternative involves building a new standalone CHPP to meet the projected installation heat and electricity needs.

Based on the evaluations, construction of new installation-specific coal-fired CHPPs was the highest ranked and lowest life-cycle cost alternative for both FWA and EAFB. This alternative has estimated capital construction costs of $201 million at FWA and $188 million at EAFB. All four regional alternatives have higher life-cycle costs than the installation-specific alternative. The regional option with the lowest capital cost is an oil- or natural gas–fired combustion turbine (CT) and heat recovery steam generator (HRSG) electrical power plant. Under this option, the existing FWA and EAFB plants would continue to be the source of heat and cogenerated electricity.

Sensitivity of the evaluation results was tested by weighting the various criteria and individual scores. The major criteria in the evaluation were security (40 percent) and life-cycle costs (30 percent). Significant changes in the criteria weighting were required to significantly change the results. Without significant changes to the weighting, changes in individual scores for a particular criterion have minimal effect.

The report concludes and recommends:

- Coal is the most secure fuel available in Interior Alaska.
- Regional solutions are more expensive and less secure than installation-specific solutions.
- Over the study period (2004 to 2028) with new plants coming online in 2012, new coal-fired CHPPs at FWA and EAFB are the highest ranked solutions.
- Because of its location, FGA has no economically justified regional solution. Electricity should be purchased directly from GVEA rather than generated at FWA and transmitted over the GVEA system. After including losses and GVEA transmission charges, it is less expensive to buy directly from GVEA.
- The U.S. Department of Defense (DoD) should participate collectively for the GFMC installations in the local electric utility's (GVEA's) next rate-making process (anticipated to occur in 2005) to ensure that its interests are represented with regard to the demand charge, transmission system use charges, cost allocations, and rate structure.
- Installations should work and participate with GVEA to pursue development of wind energy.
- FWA, FGA, and EAFB should evaluate conversion of their heat distribution systems from steam to hot water, as hot water distribution may be more cost-effective than steam.

The next steps are to:

- develop sufficient project definition to support DD Form 1391 budget level cost estimates for new coal-fired CHPPs at FWA and EAFB and for two new coal-fired CFBs at EAFB
- update the life-cycle cost analysis for the DD Form 1391 cost estimates
- choose alternative(s) and include them in the appropriate Military Construction program plan.

# Contents

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## Figures

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# Preface

This study was conducted for the Assistant Chief of Staff for Installation Management under Military Interdepartmental Purchase Request (MIPR) 3ICERG7066, "Joint Long Range Energy Study for 'Greater Fairbanks Military Complex'"; Work Unit CFE; Task GB03. The technical monitor was Hank Gignilliat, DAIM-FDF-U.

The work was managed by the Energy Branch (CF-E) of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). The CERL Project Managers were Mr. John Vavrin and Dr. Alexander Zhivov. Mr. Vavrin and Dr. Zhivov led the U.S. Army Engineer Research and Development Center (ERDC) Project Delivery Team (PDT), assisted by William T. Brown, Dr. Thomas Hartranft, Martin Savoie, Steven Sweeney, Kay McGuire, Michael Kemme, Dr. Veera Boddu, Dr. Charles Marsh, and Dr. Gary Phetteplace. The work was done by CH2M HILL under Order No. 5TS5703C267, Contract No. GS-23F-0128N. Special acknowledgement is given to the individuals listed in Table P1 for provided assistance required to conduct this study. The technical editor was William J. Wolfe, Information Technology Laboratory (ITL). Dr. Thomas J. Hartranft is Chief, CEERD-CF-E, and Michael Golish is Chief, CEERD-CF. The associated Technical Director was Gary W. Schanche, CEERD-CV-T. The Director of CERL is Dr. Alan W. Moore.

CERL and ITL are elements of the U.S. Army Engineer Research and Development Center (ERDC), U.S. Army Corps of Engineers. The Commander and Executive Director of ERDC is COL James Rowan, EN, and the Director of ERDC is Dr. James R. Houston.

Table P1. Study participants.

| Professional Association | Individuals |
|---|---|
| Alaska Department of Environmental Conservation | Mr. Luke Boles<br>Mr. John Kuterbach |
| Alaska Department of Natural Resources | Mr. Mark Myers |
| Alaska Department of Revenue | Mr. Steve Porter |
| Alyeska Pipeline | Mr. Alan Renshaw, Alyeska Pipeline<br>Mr. Ian Levitt, Alyeska Pipeline |
| Aurora Energy, LLC | Mr. Buki Wright, General Manager<br>Mr. Rufus Bunch, Power Plant Superintendent |
| Cold Regions Research Engineering Laboratory | Dr. Gary Phetteplace, Mechanical Engineer—Heat Transmission and Utilidors |
| Eielson Air Force Base | Mr. Mike Lee, Deputy Base Civil Engineer<br>Mr. Andrew Schumacher, Deputy Chief of Operations<br>Mr. Bill Havard, Operations and Maintenance Supervisor<br>Mr. Carl Heidel, Mechanical Engineer<br>Mr. Jeff Putnam, Chief, Base Development |
| Energy Solutions Group* | Dr. Charles Thomas, Senior Energy and Environmental Policy Analyst |
| Fairbanks Natural Gas | Mr. Daniel Britton, President<br>Mr. Mace Willey, Sales and Service Manager |
| Fort Greely | Mr. Lawrence Ryan, Director of Public Works<br>Mr. Terry Gibson, FGA CHPP Supervisor<br>Mr. John Whitley, FGA DPW Engineering Planner<br>Mr. Mike Etzinger, Director of Cold Regions Test Center<br>Mr. Kyle Anderson, Chief, Test Support Division |
| Fort Wainwright | Mr. Mike Meeks, Director of Public Works<br>Mr. Pat Driscoll, Operations and Maintenance Chief<br>Mr. Vic Lemay, CHPP Plant Engineer |
| Gas Technology Institute | Mr. John Kelley |
| General Services Administration | Ms. Virginia Mueller, Contract Specialist |
| Golden Valley Electric Association | Mr. Steve Haagenson, President, Chief Executive Officer; Ms. Kate Lamal, Vice President, Power Supply<br>Mr. Michael Wright, Vice President, Transmission and Distribution<br>Mr. Scott Peters, Rates |
| Headquarters, U.S. Army Corps of Engineers (HQUSACE) | Mr. John Lanzarone, Mechanical Engineer |
| Missile Defense Agency | Mr. Doug Waters, MDA<br>Mr. Timothy Berg, MDA |
| Naval Surface Warfare Center, Dahlgren Division | Mr. Ted Heller, J22 Infrastructure and Interdependency Solutions Branch |

| Professional Association | Individuals |
|---|---|
| NC Power Systems | Mr. Gary Hirschberg |
| NETL/DOE | Mr. Don Bonk |
| Regulatory Commission of Alaska | Mr. Brad Persson |
| U.S. Army Center for Health Promotion and Preventative Medicine (USACHPPM) | Ms. Debra Breindel, Environmental Protection Specialist |
| University of Alaska–Fairbanks | Mr. Dennis Witmer, Director of Arctic Energy Technology Development Laboratory |
| Usibelli Coal Mine | Mr. Steve Denton, Vice President of Business Development |
| *Unit of Science Applications International Corporation. | |

# Unit Conversion Factors

Non-SI* units of measurement used in this report can be converted to SI units as follows:

| Multiply | By | To Obtain |
|---|---|---|
| acres | 4,046.873 | square meters |
| cubic feet | 0.02831685 | cubic meters |
| cubic inches | 0.00001638706 | cubic meters |
| degrees (angle) | 0.01745329 | radians |
| degrees Fahrenheit | (5/9) x ( °F – 32) | degrees Celsius |
| degrees Fahrenheit | (5/9) x ( °F – 32) + 273.15. | kelvins |
| feet | 0.3048 | meters |
| gallons (U.S. liquid) | 0.003785412 | cubic meters |
| horsepower (550 ft-lb force per second) | 745.6999 | watts |
| inches | 0.0254 | meters |
| kips per square foot | 47.88026 | kilopascals |
| kips per square inch | 6.894757 | megapascals |
| miles (U.S. statute) | 1.609347 | kilometers |
| pounds (force) | 4.448222 | newtons |
| pounds (force) per square inch | 0.006894757 | megapascals |
| pounds (mass) | 0.4535924 | kilograms |
| square feet | 0.09290304 | square meters |
| square miles | 2,589,998 | square meters |
| tons (force) | 8,896.443 | newtons |
| tons (2,000 pounds, mass) | 907.1847 | kilograms |
| yards | 0.9144 | meters |

**Système International d'Unités* ("International System of Measurement"), commonly known as the "metric system."

# 1 Introduction

## Background

Currently, the U.S. Army and the U.S. Air Force (the Services) and the Missile Defense Agency (MDA) are pursuing independent heat and power solutions to meet their needs. A number of studies have addressed heat and power issues for Fort Wainwright (FWA) and Eielson Air Force Base (EAFB) over the past decade. Generally, these studies have considered the same basic alternatives, but only for the particular installation. Previous energy studies for the Fairbanks region include:

- *Determination of Practical Options for Providing Heat and Electrical Power to Fort Wainwright* (U.S. Army Center for Public Works, Directorate of Engineering, Mechanical and Energy Division, Report No. EM-96002, August 1996) evaluated the Fort Wainwright Central Heat and Power Plant (CHPP) and identified practical options for providing heat and power for the next 25 years.
- *Central Heat and Power Plant Refurbishment Study* (U.S. Army Center for Public Works, Directorate of Engineering, Mechanical and Energy Division, Report No. EM-96003, August 1996) examined the CHPP refurbishment option in detail.
- *Central Heat and Power Plant Life Cycle Cost Study* (U.S. Army Center for Public Works, Directorate of Engineering, Mechanical and Energy Division, Report No. EM-96004, August 1996) developed life-cycle costs for several long-term heat and power alternatives.
- *Central Heat and Power Plant Study: Eielson AFB* (CH2M, 1997, prepared for Air Force Civil Engineer Support Agency) evaluated seven alternative planning options for the CHPP and three for the electrical distribution system.
- *Environmental and Engineering Options Study: Central Heat and Power Plant, Eielson AFB, Alaska, Final Report* (Earth Tech, Inc., September 2001, prepared for Air Force Center for Environmental Excellence) evaluated the operational performance and condition of the Eielson AFB CHPP steam and electrical power production and distribution systems over a 30-year period and made recommendations for improving current operations or implementing alternative methods of operation.
- *Additional Options for Increased Power Reliability, Ground-Based Midcourse Missile Defense Program Ballistic Missile Defense System*

*Test Bed, Fort Greely, Alaska* (Black & Veatch, February 2003) evaluated relocating an existing Golden Valley Electric Association (GVEA) generation unit from Chena to the immediate area versus locating four 1.8-megawatt (MW) engine-generators to provide backup generation.

- *Utility Study: Fort Wainwright, Alaska—U.S. Army Alaska, Final Submittal* (U.S. Army Corps of Engineers, Alaska District, April 2003) evaluated the existing utility distribution system and recommended a revitalization program to ensure that utility distribution can continue to meet the Army's needs.
- *Interim Study: Fort Wainwright, Alaska—Conversion of CHPP to Heating Only and Provide Backup Electrical Generators* (Science Applications International Corporation, Draft Report, March 2003, prepared for Construction Engineering Research Laboratory) evaluated the conversion of the Fort Wainwright CHPP to a central heating-only plant (CHP), electrical system substation upgrades, and provision of sufficient onsite backup electric power generation capacity to enable operation of the CHP and all critical loads.
- *Central Heating and Power Plant Alternatives Review: Fort Wainwright, Alaska* (ERDC/CERL Technical Report 03-11, May 2003) was an independent technical assessment of the Fort Wainwright CHPP, addressing short-term solutions for future energy requirements based on expanding missions such as the Stryker Brigade Combat Team, a new high-tech training simulator, and a new hospital.

This study was undertaken to evaluate installation-specific and regional options for providing heat and power to FWA, EAFB, Fort Greely (FGA), and Ground-Based Midcourse Defense (GMD). The evaluation includes projects planned by FWA and EAFB to repair or upgrade existing central heat and power plant (CHPP) facilities and interconnections to Golden Valley Electric Association (GVEA). It does not include consideration of installation heat and electricity distribution systems. This study identifies and evaluates long-term (25-year) regional and installation-specific alternatives for providing heat and electricity to FWA, FGA, and GMD installation adjacent to FGA, and EAFB, collectively referred to as the Greater Fairbanks Military Complex (GFMC). This study involved a conceptual analysis that sets the stage for a follow-up, in-depth evaluation of selected options and further steps toward developing final design concepts. It does not provide detailed designs, plans, or specifications. Figure 1 shows the locations of the GFMC installations.


Figure 1. Greater Fairbanks military complex.

The evaluation was done independently of specific ownership considerations. Any of the evaluated alternatives could be pursued as a privatized solution. The evaluation did not identify any constraints to privatization of the central heat and power functions at FWA or FGA. (The Boeing Company is operating GMD. The Air Force has exempted EAFB from privatization.)

Prior to selecting alternatives to be evaluated, a number of possible technologies (including renewable resources) and approaches were reviewed for viability, practicality, and proven performance. Based on this review, the selected technologies are circulating fluidized-bed combustion boilers (CFBs)/steam turbine generators (STGs) for coal and combustion turbines (CTs), and heat recovery steam generators (HRSGs) and STGs for oil or natural gas.

## Objective

This objective of this study was to evaluate installation-specific and regional options for providing heat and power to FWA, EAFB, FGA, and GMD, specifically, to identify and evaluate those heat and power supply alternatives that provide a high quality of service at reasonable cost while

complying with current environmental laws and good engineering and utility operating practices.

## Approach

The Engineer Research and Development Center's Construction Engineering Research Laboratory (ERDC-CERL) established a project delivery team (PDT) led by the CERL Program Manager and consisting of members from CERL and ERDC's Cold Regions Research and Engineering Laboratory (CRREL). The PDT was responsible for project management, data collection, environmental assessment, security assessment (in collaboration with Dahlgren Defense Program Office for Mission Assurance), and privatization analysis and assisted the contractor in report preparation. ERDC awarded a contract to CH2M HILL in August 2003 to perform the technical study.

A Joint Review Panel (JRP) was established to provide oversight and strategic direction to the PDT. The PDT worked with the installations for onsite data gathering. In-progress reviews (IPRs) were held monthly to inform JRP members about the progress of the study and to solicit real-time feedback and input.

The effort included a kickoff meeting, monthly interim progress reports, monthly conference calls with the Joint Review Panel (JRP), onsite installation in-briefs and out-briefs, and JRP briefings. A final out-brief to the Secretariats and Director of MDA was provided in April 2004. Meetings were held or telephone contact was made with the various organizations that provide fuel, heat, or electricity in the Fairbanks area. The purpose of this study was discussed, information obtained, and potential solutions discussed.

Background information was gathered on the energy supply situation in Interior Alaska, the availability of fuels and the existing energy infrastructure, and on possible technologies suitable to provide long-term heat and power solutions for the GFMC installations. Evaluation criteria for fuels and alternative heat and power solutions were developed. Life-cycle costs were developed for each alternative and used in the evaluation along with other criteria such as security, impact on Alaska infrastructure, and air and water quality. The results of the analysis are presented to allow the U.S. Department of Defense (DoD) to make an informed decision about heat and power solutions for the installations.

Specific steps included:

1. Developing a load forecast for heat and power for each installation.
2. Determining air quality, solid waste, and water-related permitting issues.
3. Defining and developing the evaluation criteria and recommend weighted averages (sensitivity analysis) for the identified courses of action. The evaluation criteria include security, life-cycle costs, capital costs, air and water quality, cost stability, impact on Alaska infrastructure, water and solid waste reduction, and operating cost.
4. Conducting an initial evaluation of viable options for each installation.
5. Evaluating the ability of local utility providers to supply current and future needs of the installations, with a recommendation on the feasibility of privatization versus continued ownership and operation by the Services and MDA.
6. Determining the feasibility of standalone decentralized heating of new facilities.
7. Determining the feasibility of new third-party central plants or the purchase of heat and/or power from the local utility company.
8. Examining the use of an enhanced-use leasing authority to upgrade and operate existing systems.
9. Determining the feasibility and cost of other heating and power options.
10. Evaluating regional solutions for providing power and heat to the installations.
11. Providing recommendation(s) on the best regional and installation-specific course(s) of action.
12. Conducting a 2-day Strategic Energy Forum in Fairbanks.

## Scope

The alternatives evaluated include installation-specific alternatives (continued operation of existing plant and new plant) and regional alternatives to provide power or both heat and power. This study does not provide any detailed designs, plans, or specifications.

## Mode of Technology Transfer

The results of this study will be provided directly to the project sponsor and involved organizations. Additionally, this report will be made accessible through the World Wide Web (WWW) at URL:

http://www.cecer.army.mil

# 2 Project Overview

## Greater Fairbanks Military Complex

Fort Wainwright is adjacent to and at the southeast corner of the city of Fairbanks. Eielson Air Force Base is approximately 20 mi southeast of Fairbanks along State Highway 2 (Richardson Highway). FGA and GMD are adjacent, approximately 110 miles southeast of Fairbanks (85 mi south of EAFB) along the Richardson Highway, just south of Delta Junction, AK (Figure 2). FWA and EAFB are located within the Fairbanks North Star Borough (FNSB), which in 2001 had a population of 83,694. FGA and GMD are located near the City of Delta Junction (an unincorporated area). In 2001, Delta Junction had a population of 5,702. The combined population of these two areas (89,396) is 14 percent of the 2001 Alaska population of 634,892. By Lower 48 standards, the Interior Alaska population is very small. Heat and power solutions will be at a correspondingly smaller scale than those in the Lower 48.

FWA has a resident and working population of about 10,000. Its historical peak electrical demand is 18.4 megawatts (MW) in comparison to the GVEA peak of 184.5 MW. EAFB has a resident and working population of about 12,000. Its historical peak electrical demand is 17.1 MW. FGA has a resident and working population of about 820. It has a peak demand of about 2.4 MW. GMD is under construction and, when operational, is expected to have a resident and working population of about 350. It has a current peak electrical demand of about 3 MW.

## Projected Electrical Loads

Figure 3 shows the projected peak electrical demands (assuming –60 °F temperatures) for each GFMC installation over the study period. For FWA and EAFB, the peak demand is assumed to grow at 2 percent per year after 2008. For FWA, there is an increase in projected peak demand from the new Simulator Building (2004), the new Bassett Hospital (2006), and the Stryker Brigade Combat Team and Family Housing (2007), followed by a decrease resulting from the demolition of the old Bassett Hospital (2008).

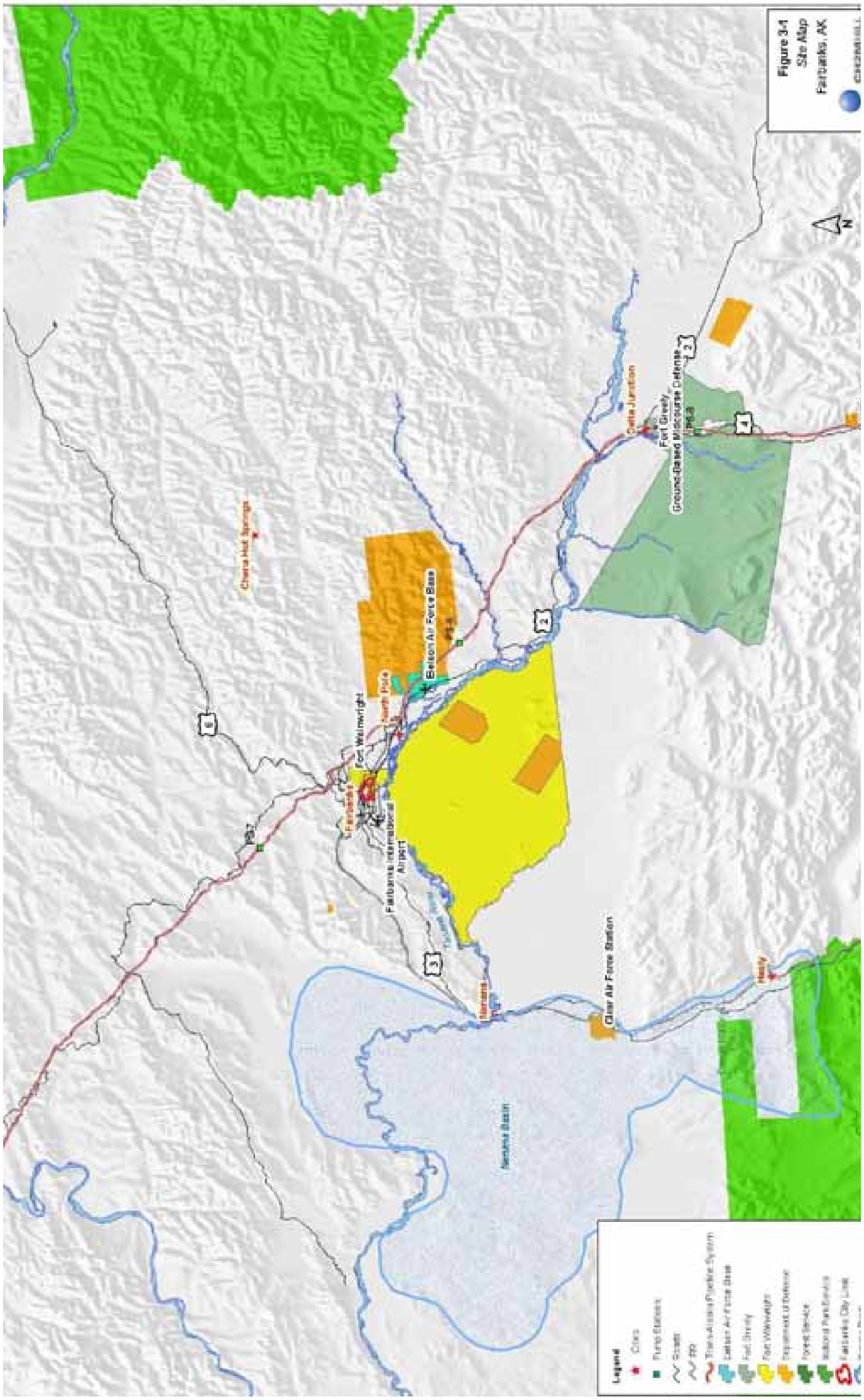


Figure 2. FWA site map.

## Renewable Energy Resources

The two potential renewable energy resources in Interior Alaska are solar and wind power. Neither provides a power supply that would replace fossil fuel–based generation. However, they do provide a potential opportunity to meet Executive Order 12856 renewable energy goals. Photovoltaic solar power would be very expensive (estimated at more than $1 per kilowatt-hour [kWh]). GVEA is pursuing development of 10 to 20 MW of wind generation. Wind power development, if pursued by the military, should be in conjunction with GVEA. The military could participate as a project owner if desired.

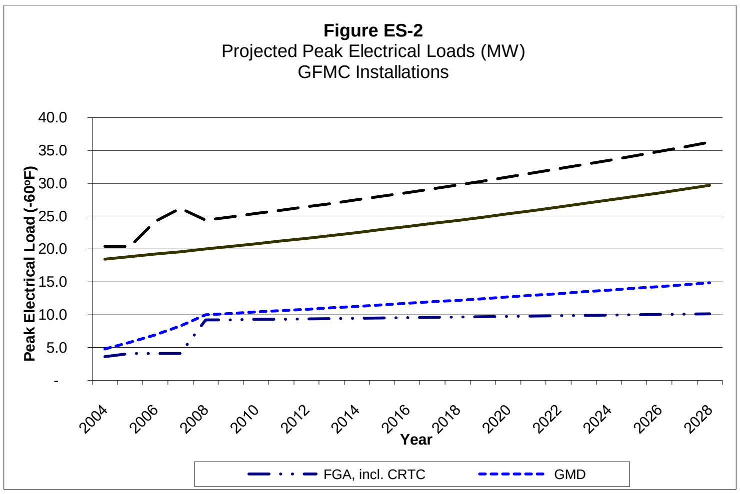


Figure 3. Projected peak electrical loads (megawatts [MW]) for GFMC installations.

Use of renewable energy would offset fossil fuel consumption (coal, oil, and possibly natural gas), reducing emissions in direct proportion to the reduced fuel use. Minimum operating levels for the installation boilers and steam turbine generators (STGs) may at times limit the ability to offset the fuel consumption.

## Fuel Alternatives and Evaluation

Interior Alaska fuel alternatives consist of coal, oil or oil distillates (collectively referred to as oil or fuel oil in this report), and, perhaps, natural gas.

There are vast reserves of coal in the Healy, AK, area about 80 air miles south of Fairbanks that are being mined by Usibelli Coal Mine, Inc. (UCM), at the only active coal mine in Alaska. This has been the coal source for both FWA and EAFB. Price projections for this coal indicate that it is expected to decline in price in real dollar terms.

North Slope oil and oil distillates (diesel fuel arctic, naphtha, etc.) are available from two refineries located at North Pole, AK, about halfway between FWA and EAFB. This oil is generally priced to reflect oil prices on the West Coast of the United States. North Slope oil production is projected to decline over the next 25 years.

A natural gas pipeline to Fairbanks does not currently exist. However, in January 2004 two competing applications were filed with the State of Alaska to build a natural gas pipeline to transport North Slope natural gas to Canadian and U.S. markets. The sponsors indicated in-service dates of 2010 to 2012. If the pipeline is completed, natural gas may be available in the Fairbanks area. The price is expected to reflect Upper Midwest natural gas prices.

Fuels were evaluated separately from the alternatives to capture the relative merits of each fuel from the perspectives of availability/reliability, security, price volatility/cost stability, environmental, and waste reduction independent of a particular technology or alternative. Previous studies had considered emissions issues, but not the other criteria.

Coal was ranked high because of its vast nearby supply, its security as an indigenous fuel that is easily transported and stored, and its projected stable cost. It received low scores for environmental and waste reduction factors.

Oil and oil distillates received relatively lower scores for availability/reliability, security (because of the dependence on the single Trans-Alaska Pipeline System [TAPS] from the North Slope), and price volatility/stability. It received high scores for environmental and waste reduction considerations.

Natural gas received the same lower scores as oil for availability/reliability (on the assumption the proposed pipeline gets built) and security because its delivery would be over a single pipeline. It also is expected to have high price volatility. Natural gas received a slightly higher score for environmental considerations than oil.

The evaluation scoring results were normalized (on a scale of 0 to 1) so that the highest scored fuel or fuel combination had a score of 1.00. The fuel alternatives were scored as follows:

- coal (as the primary fuel with gas backup): 1.00
- coal only and coal with oil backup: 0.98
- oil and oil distillates: 0.76
- natural gas (as the primary fuel): 0.77

## Environmental Considerations

The evaluation of alternatives did not identify any issues that would prevent new plant development. Fairbanks is a CO management/NAA. Because upgrade of the existing FWA or EAFB CHPPs would eliminate existing bottlenecks that limit emissions, an upgrade can be expected to result in a need to re-permit the existing CHPPs and retrofit additional emission control systems. If the existing CHPPs are shut down, their emissions can be used as offsets for the new CHPPs.

## Electricity Considerations

GVEA is the only nonmilitary provider of electricity and electricity transmission in Interior Alaska. No other power producers or transmission providers are available to the installations. FGA and GMD rely on the GVEA transmission system for their electricity supply and have onsite backup generation for those times when the GVEA transmission system is out of service. In the past, the GVEA system has been subject to transient voltage excursions and occasional outages that have resulted in service interruptions to the installations.

GVEA has expressed a desire to work with the GFMC installations on electricity supply and, if desired, combined heat and power. It has indicated an interest in discussing possible GVEA development of new CHPPs at either FWA or EAFB or on a regional basis.

## FGA and GMD Solutions

This evaluation did not identify a need for new heat solutions at FGA or GMD. The existing boiler facilities at FGA are about 10 years old and have more than adequate capacity to meet loads over the study period. FGA's electricity needs can be met by either FWA generation or purchases from GVEA. GMD has purchased new hot water boilers to heat installation facilities and is purchasing its electrical needs from GVEA with engine-generator sets for backup. A regional power plant could meet the electrical needs of both installations. However, because the installations are 84 miles from EAFB and have relatively small heat loads, including them in a regional heat solution is not justified.

## Current Situation at FWA and EAFB

Both FWA and EAFB are in the midst of repairing their 50-year-old CHPPs (boilers and related equipment, coal handling facilities, etc.) and

adding new baghouses for particulate emissions control. The installations have made significant expenditures over the past few years and plan significant expenditures for the next several years. However, even with those repairs, the basic infrastructure will still be old.

Both FWA and EAFB have sufficient boiler capacity to meet their heat loads for the 25-year study period. However, both will need additional electrical generation to meet their increasing power needs. Depending on the severity of weather conditions or outages of on-base generation, FWA will need to purchase electricity from GVEA to meet its peak or backup needs. EAFB is self-sufficient for electricity until about 2012. If its projected 2 percent per year electrical load growth does not occur, the need to buy power from GVEA will be postponed.

## Alternatives Evaluated for FWA and EAFB

The alternatives evaluated are described at the beginning of this Chapter. The evaluations assumed that new facilities would be brought online at the beginning of 2012, providing lead time for planning, permitting, design, and construction. The existing CHPPs would continue to operate until that time.

The analysis calculated that overall fuel efficiency ranges from about 45 percent for alternatives where electricity generation is relatively high compared to heat generation (Upgrade) to as high as 90 percent when cogeneration and heat production are predominant (New CT/HRSG CHPP). Heat production is much more fuel-efficient than electricity production. The fuel efficiency of standalone coal-fired electricity production is about 30 percent.

## Life-Cycle Cost Evaluation

Table 1 lists the estimated capital cost for each alternative, not including the cost of planned investments. Note that, at this level of project definition, uncertainty associated with the estimates is on the order of +50 percent and –30 percent. However, for purposes of comparative analysis, the estimates are valid.

The alternatives were evaluated on the basis of life-cycle costs (Figure 4). The lowest life-cycle cost alternative at FWA was continued operation of the existing CHPP at 1.2 percent over a new coal-fired CHPP. For EAFB the lowest life-cycle cost was for a new coal-fired CHPP. On a combination

basis, the lowest life-cycle cost alternative was new coal-fired CHPPs at each installation. The next lowest life-cycle cost alternative combination is to upgrade EAFB and continue to operate the FWA CHPP.

Table 1. Capital costs of alternatives.

| Solution Category | Alternative | Description | Capital Cost Estimate (2004 $ millions) |
|---|---|---|---|
| *Regional* | Electricity Only | | |
| | Region 1 | Coal CFB/STG Power Plant | $309 |
| | Region 2 | CT/HRSG Power Plant | $165 |
| | Heat and Power | | |
| | Region 3 | CFB/STG CHPP | $590 |
| | Region 4 | CT/HRSG CHPP | $303 |
| | CHPP Demolition | | |
| | Fort Wainwright | | $14 |
| | Eielson AFB | | $14 |
| *Installation-Specific* | Fort Wainwright | | |
| | FWA-1 | Repair Only | $0[1] |
| | FWA-2 | Repair and Upgrade | $110 |
| | FWA-3 | Follow Heat Curve | $0[1] |
| | FWA-5 | New CFB/STG CHPP | $201 |
| | FWA-6 | New CT/HRSG CHPP | $100 |
| | Eielson AFB | | |
| | EAFB-1 | Repair Only | $0[1] |
| | EAFB-2 | Repair and Upgrade | $86 |
| | EAFB-3 | Follow Heat Curve | $0[1] |
| | EAFB-4 | Upgrade w/ CFB/STG CHPP | $105 |
| | EAFB-5 | New CFB CHPP | $188 |
| | EAFB-6 | New CT/HRSG CHPP | $88 |

[1] The costs of routine and major maintenance are included in the operating costs.

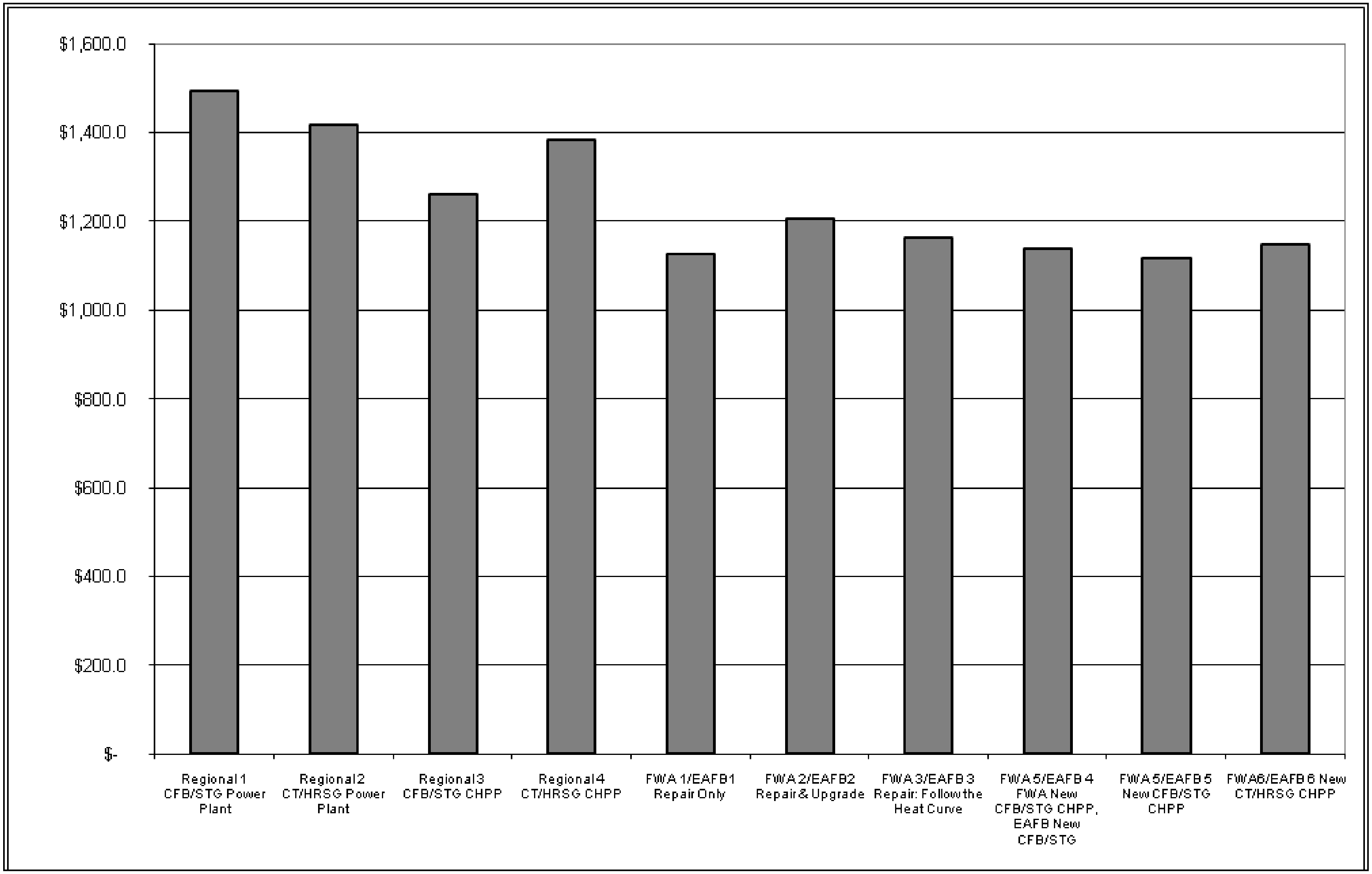


Figure 4. Summary of life-cycle cost analysis.

The regional alternatives have higher life-cycle costs than the installation-specific alternatives. For the regional power plant alternatives, it is expensive to operate three plants concurrently (existing CHPPs through 2012 and the new power plant for 25 years). There is also the added cost of GVEA transmission charges. For the regional CHPP alternatives, higher capital investment is required because of the heat transmission system. Fuel costs are 10 percent higher to account for losses in the conversion from steam to hot water and for transmission losses. GVEA transmission charges are also included. For the oil-fired CT alternatives, there is a significant fuel oil cost to generate the necessary heat. Maintaining the existing CHPPs in standby mode for 3 years also contributes to the life-cycle cost of the alternative. Labor costs are somewhat lower for the regional CHPP alternatives.

## Alternatives Evaluation

The alternatives were evaluated on the basis of:

- Security 40%
- Life-Cycle Costs 30%
- Capital Cost[1] 7%
- Air and Water Quality 5%
- Cost Stability 5%
- Impact on Alaska Infrastructure 5%
- Water and Solid Waste Reduction 5%
- Operating Cost[*] 3%

The use of separate weightings for Life-Cycle Costs, Capital Cost, and Operating Cost (a total of 40 percent) was done under the direction of the CERL and the JRP for clarity. It is recognized that Capital Cost and Operating Cost are subcomponents of life-cycle cost. Therefore, these subcomponents are weighted twice: (1) by themselves, and (2) within the life-cycle costs.

[*] Included as a separate evaluation criterion even though it is included in life-cycle costs because of the different funding mechanisms: capital from the service and operating costs from the installation.

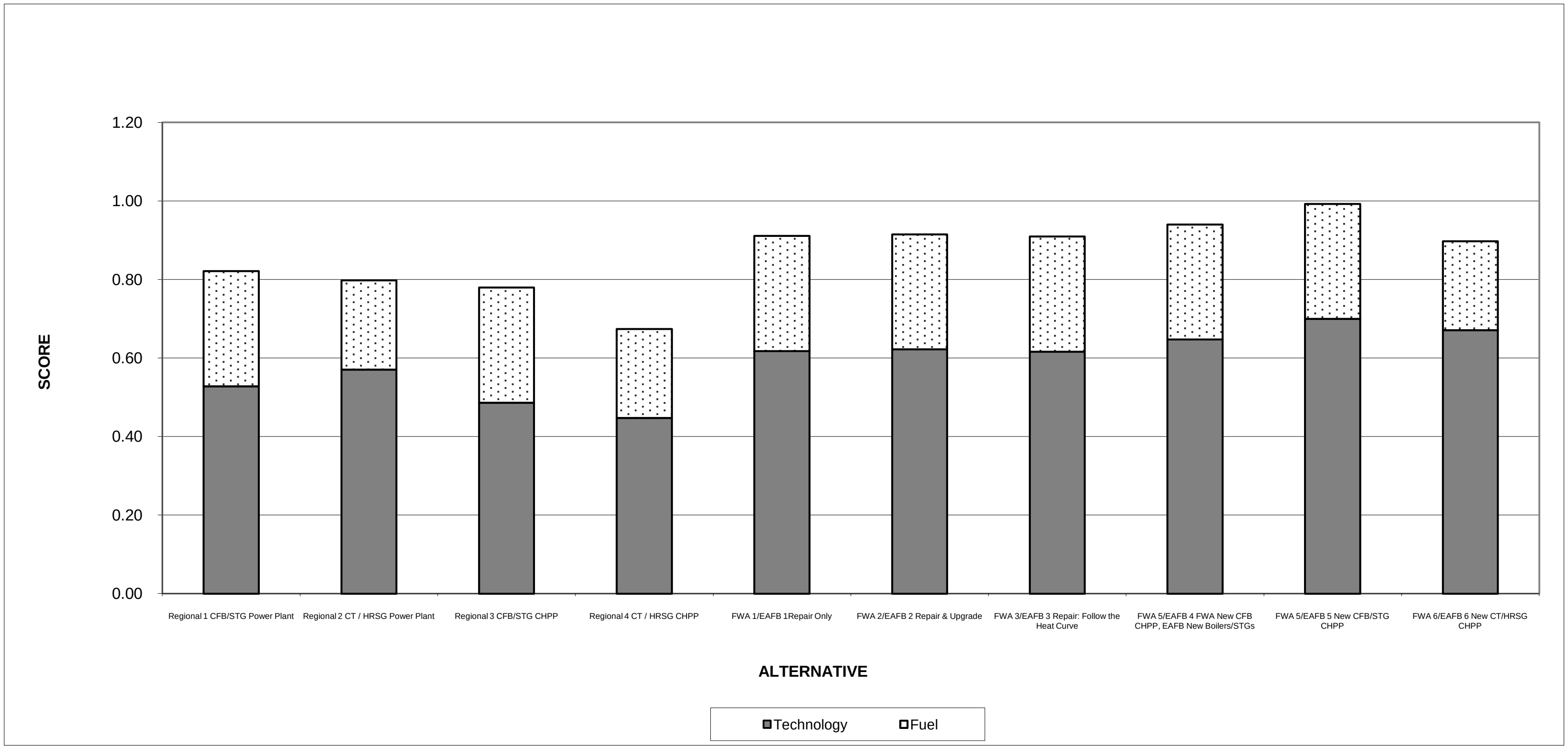


Figure 5. Overall evaluation scores.

Figure 5 shows the results based on the evaluation. Note that the separate scores for fuel and the alternative were each normalized (on a scale of 0 to 1) with the highest ranked fuel or alternative receiving a score of 1.00. Because the existing CHPPs are coal only and coal only was not the highest ranked fuel alternative, the highest ranked alternative is not 1.00, but 0.99. The lower portion of each bar represents the non-fuel ranking of each alternative (security, life-cycle cost, etc.). The upper portion of each bar represents the fuel ranking for the alternative. It can be seen that the highest ranked alternative is a new coal-fired CHPP at both FWA and EAFB. The other installation-specific alternatives ranked essentially the same. The regional alternatives ranked the lowest.

## Evaluation Results

Table 2 lists the alternatives in descending order of ranking based on the evaluations. For the regional alternatives, it is possible to locate the facility outside the secure, guarded area ("outside the fence") of both FWA and EAFB. The score for this "outside the fence" regional approach is indicated parenthetically; these scores are lower because of their lower security.

Table 2. Alternatives in descending order of ranking.

| Evaluated Score | Alternative |
|---|---|
| 0.99 | New Coal-Fired CHPPs at FWA and EAFB |
| 0.94 | New Coal-Fired CHPP at FWA and New Boilers at EAFB |
| 0.92 | Repair and Add STG Capacity at FWA and EAFB |
| 0.91 | Repair the FWA and EAFB CHPPs |
| 0.91 | Repair and Operate as Fuel-Efficiently as Possible |
| 0.90 | New Oil- or Natural Gas–Fired CHPPs at FWA and EAFB |
| 0.82 (0.76) | New Regional Coal-Fired CHPP |
| 0.80 (0.74) | New Regional Coal-Fired Power Plant |
| 0.74 (0.72) | New Regional Oil- or Natural Gas–Fired Power Plant |
| 0.67 (0.61) | New Regional Oil- or Natural Gas–Fired CHPP |

## Sensitivity Analysis

Sensitivity of the evaluation results was tested in terms of changes to capital costs, lower-than-expected load growth, and the weighting of the various criteria and individual scores. For FWA, an 11 percent decrease in the new coal-fired CHPP capital cost would result in the same life-cycle cost as for continued operation of the existing CHPP. Conversely, a $12.6 million increase in the existing CHPP capital costs over the 25-year period would result in a new CHPP and continued operation of the existing CHPP hav-

ing the same life-cycle costs. For EAFB, the new CHPPs would need to increase in cost by 21 percent to have the same life-cycle costs. If the projected electrical load growth does not materialize, continued operation of the existing CHPP at FWA has the lowest life-cycle cost. At EAFB, a new CHPP has the lowest life-cycle cost. Significant changes in the criteria weighting were required to significantly change the results. Without such weighting changes, changes in individual scores for a particular criterion have minimal effect.

## Additional Insights

Based on the investigations described here, the following insights are offered:

1. The DoD should negotiate UCM coal contracts for more than 5-year terms, as is the case with the current contract. The longer term should result in lower prices by allowing UCM to amortize its investments over a longer contract life.
1. The DoD should attempt to negotiate lower coal prices from UCM when the current contract expires in 2007.
2. The DoD should participate collectively for all of the GFMC installations in GVEA's next rate-making process (anticipated to occur in 2005) to ensure that its interests are represented with regard to the demand charge, transmission system use charges, cost allocations, and rate structure.
3. At FGA, electricity should be purchased directly from GVEA rather than generated at FWA and transmitted over the GVEA system because after including losses and GVEA transmission charges, it is less expensive to buy directly from GVEA.
4. The installations should work and participate with GVEA in the pursuit of developing wind energy.
5. FWA, FGA, and EAFB should consider conversion of their heat distribution systems from steam to hot water because in light of the need to renovate the systems, hot water heat distribution may be more appropriate and more cost-effective than steam.

# 3 Energy-Related Considerations in Alaska

## Interior Alaska Climate

Interior Alaska has a continental-type climate marked by large temperature variations from winter to summer. The climate is characterized by large daily and annual temperature ranges, low humidity, and relatively light and irregular precipitation.

The climate is conditioned mainly by the response of the landmass to large changes in solar heat received during the year. The sun is above the horizon from 18 to 21 hours during June and July. During this period, daily average maximum temperatures reach the lower 70s. Temperatures of 80 °F or higher occur on about 10 days each summer. In contrast, from November to early March when the period of daylight ranges from 10 to less than 4 hours per day, the lowest temperature readings fall below 0 °F regularly. Low temperatures of -40 °F or colder occur each winter.

The range of temperatures in summer is comparatively low, from the lower 30s to the mid-90s. In winter, this range is larger, from about -65 to 45 °F. This large range of winter temperatures reflects the great difference between frigid weather associated with dry northerly airflow from the Arctic to mild temperatures associated with southerly airflow from the Gulf of Alaska, accompanied by Chinook winds off the Alaska Range 80 miles south of Fairbanks.

Snow cover is persistent from October through April. Snowfalls of 4 in. or more in a day occur only three times on average during winter. Blizzard conditions are almost never seen as winds are above 20 miles an hour less than 1 percent of the time. Precipitation normally reaches a minimum in spring and a maximum in August, when rainfall is common. During summer, thunderstorms occur on an average of about 8 days. Thunderstorms are about three times more frequent over the hills to the north and east. Damaging hail or wind rarely accompanies thunderstorms around Fairbanks.

Rolling hills reach elevations up to 2,000 ft above Fairbanks to the north and east. During winter, the uplands are often warmer than Fairbanks, as cold air settles into the valley. In some months, temperatures in the uplands will average more than 10 degrees warmer than in Fairbanks. During

summer, the uplands are a few degrees cooler than the city. Precipitation in the uplands around Fairbanks is heavier than it is in the city by roughly 20 to 50 percent. Fairbanks exhibits the characteristics of an urban heat island, especially during winter. Low lying areas nearby, such as the community of North Pole, are often colder than the city, sometimes by as much as 15 degrees.

With temperatures of -20 °F or colder, ice fog frequently forms in the city. Cold snaps accompanied by ice fog generally last about a week, but can last 3 weeks in unusual situations. The fog is almost always less than 300 ft deep, so the surrounding uplands are usually in the clear with warmer temperatures. Visibility in the ice fog is sometimes quite low and can hinder aircraft operations for as much as a day in severe cases. Aside from the low visibility in winter ice fog, flying weather in Fairbanks is quite favorable, especially from February through May when crystal clear weather is common and the length of daylight is rapidly increasing.

The FGA/GMD area experiences much more surface wind, which follows a normal pattern of strongest speeds in the winter and lightest speeds in summer. Wind direction follows the orientation of the Tanana Valley (east-southeast) from early fall to early spring and follows the orientation of the Delta River (southwest) from May through July. Wind averages and extremes are high when compared to other Interior Alaska locations. With strong pressure gradients from both the Tanana and Delta River valleys, the FGA area experiences a venturi effect that accentuates the already high speeds.

From the perspective of heat and power, the predominant concern is extremely low wintertime temperatures. Temperatures below 0 °F occur regularly, and extreme lows below -58 °F have been recorded in three of the winter months. The minimum temperatures occur in December, January, and February; the average minimum temperature is -16.5 °F. Extreme minimum temperatures for these months are:

- December: -62 °F (1961)
- January: -61 °F (1969)
- February: -58 °F (1993).

A loss of heat can quickly cause a facility to freeze, resulting in irreparable damage. Loss of power can have similar consequences. Outages of more than a couple of hours represent a danger to life and safety as well as to

facilities. As a result, a historical and appropriate concern is that heat and power facilities be reliable and redundant.

American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) climate conditions for the Fairbanks regions are:

- Winter Outdoor Design Dry-Bulb Temperature (99 percent): -51 °F
- Summer Outdoor Design Dry-Bulb Temperature (1 percent): 82 °F
- Summer Outdoor Design Wet-Bulb Temperature (1 percent): 64 °F

Table 3 shows the average total monthly heating and cooling-degree days (Base 65) for the period 1971 through 2000. These averages are plotted in Figure 6, which shows that the climates for the three installations are very similar.

Table 3. Average total monthly heating- and cooling-degree days (1971–2000).

| | FWA | | EAFB | | FGA/GMD | |
|---|---|---|---|---|---|---|
| Month | HDD | CDD | HDD | CDD | HDD | CDD |
| January | 2,315 | — | 2,298 | — | 2,097 | — |
| February | 1,926 | — | 1,910 | — | 1,759 | — |
| March | 1,670 | — | 1,653 | — | 1,576 | — |
| April | 999 | — | 996 | — | 987 | — |
| May | 504 | — | 505 | — | 536 | — |
| June | 179 | 20 | 195 | 15 | 228 | 1 |
| July | 121 | 42 | 122 | 24 | 144 | 12 |
| August | 283 | 11 | 282 | 9 | 308 | 12 |
| September | 615 | 1 | 607 | — | 620 | 2 |
| October | 1,287 | — | 1,290 | — | 1,270 | — |
| November | 1,882 | — | 1,885 | — | 1,761 | — |
| December | 2,199 | — | 2,202 | — | 2,016 | — |
| *Total* | *13,980* | *74* | *13,945* | *48* | *13,302* | *27* |

For purposes of this study, the weather conditions at the three installations are identical.

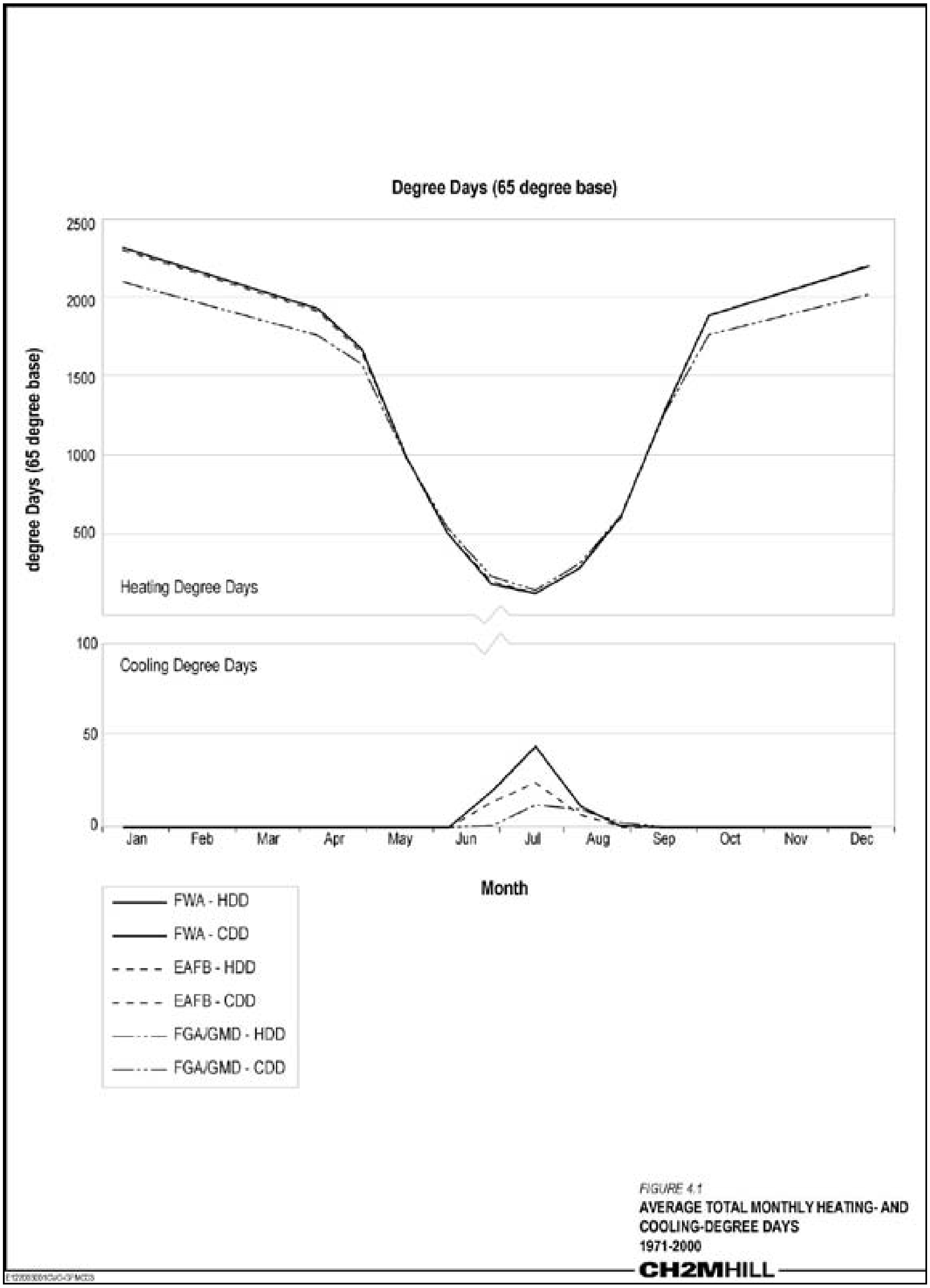


Figure 6. Average total monthly heating and cooling-degree days fir three subject installations.

## 1.1 Alaska Utility Regulatory Considerations

Evaluation of heat and power supply alternatives for each installation and on a regional basis involves consideration of whether State of Alaska regulatory requirements might preclude an alternative, particularly with regard to ownership issues and use of the GVEA system for electric power transmission.

The information and analysis presented is based on a review of existing regulations and precedents set in past regulatory decisions. No legal opinions are given. However, regulatory opportunities and constraints for possible heat and power supply options are identified, including privatization of on-installation utility systems. Some regulatory areas are uncharted and, therefore, are identified as uncertain in this report.

### General Background

Each GFMC installation owns and operates its own CHPP and on-installation steam distribution and electric distribution facilities. These operations have never been subject to commercial regulation by the State of Alaska or any other regulatory body.

Each installation is also within the GVEA service area, which is the sole electric utility serving the greater Fairbanks area. GVEA has a power sales agreement with each installation and sells electricity to each under its GS-2 rate schedule.

The installations do not have natural gas service. Fairbanks Natural Gas (FNG) has a distribution system that serves parts of Fairbanks directly to the northwest of FWA. While FWA is not in FNG's current approved service area, it likely would be easy for FNG to obtain approval to extend its service to include FWA facilities. The other installations are remote from the FNG service area.

Aurora Energy (AE) provides district steam and hot water heat to downtown Fairbanks. Similar to the natural gas utility, AE's district heat system could be extended to include FWA. AE produces steam and hot water for its district heating system through cogeneration at a coal-fired plant in downtown Fairbanks. All power produced at the plant is sold to GVEA.

### Energy Utility Supplies Provided in Bulk from Off-Installation Entities

#### *General Regulatory Setting in Alaska*

The Regulatory Commission of Alaska (RCA) regulates electric, natural gas, steam, and other utility systems in Alaska. All privately owned utilities are regulated by the RCA. Publicly owned systems are subject to economic regulation by municipal and borough authorities. However, these authorities can request that the RCA assume jurisdiction.

Utility cooperatives such as GVEA can choose to remove themselves from economic regulation by the RCA. Some cooperatives have, in fact, opted out of economic regulation.* The energy utilities serving the greater Fairbanks area, GVEA (a cooperative), FNG (privately owned), and AE's district heat utility (privately owned), are all regulated by the RCA.

The Federal Energy Regulatory Commission (FERC) has no jurisdiction over electric utilities in Alaska. Its jurisdiction is limited to public utilities that engage in wholesale electricity transactions that are interstate commerce. Because Alaska's transmission systems do not connect with other electric transmission systems, the flow of electricity over those lines is wholly intrastate and so they do not come under FERC's jurisdiction. (FERC does have jurisdiction over hydroelectric facility licensing in Alaska and tariff setting for the Trans-Alaska Pipeline System [TAPS]).

#### *Jurisdiction*

The RCA operates under a broad statutory grant of authority pursuant to Title 42 of the Alaska Statutes to "do all things necessary or proper to carry out the purposes and exercise the powers expressly granted or reasonably implied" under the statute. The Alaska Supreme Court has held this delegation of power to the RCA to be broad in scope as long as the RCA acts within the stated purpose of the statute. Among its specifically enumerated powers, the RCA can:

- Investigate and establish just, fair, and reasonable rates, classifications, rules, regulations, practices, services, and facilities for a public utility.
- Regulate the service and safety of a public utility's operations.
- Initiate court proceedings to protect and promote the interests of Alaska.

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* Even when cooperatives opt out of rate and service quality regulation, they are still subject to the RCA's authority over service area certification.

In addition, the RCA is tasked with the duty of promoting the conservation of resources used in the generation of electric energy when it establishes electric rates. These regulatory powers cover every type of public utility engaged or proposing to engage in a utility business inside the state except for those entities specifically exempted by statute.

Under Alaska law, a public utility includes any entity that owns, operates, manages, or controls any plant, pipeline, or system for furnishing electric, natural gas, steam, telephone, water, sewer, or solid waste service to the public for compensation.

A threshold question is whether an entity providing utility services is a public utility subject to RCA jurisdiction. For gas, steam, and other utilities except electric, the act defines the public as a group of 10 or more customers. In the case of electric utility service, the public is defined as one or more customers. However, if an electric utility receives revenues of less than $50,000, it is not considered a public utility.

Independent power producers with revenues greater than $50,000 can operate outside of RCA regulation if they only sell on a wholesale basis to utilities that are regulated by the RCA. Steam producers can also make wholesale sales and remain unregulated if they serve fewer than 10 customers, including retail customers.

*Service Areas*

Normally, companies providing electric, gas, or district steam services to the public must have a certificate before providing those services. That is, each public utility or pipeline carrier must obtain a certificate of public convenience and necessity (CPCN), which describes the authorized service area and scope of operations. To issue a certificate, the RCA must find the applicant to be fit, willing, and able to provide the utility service requested. The RCA will grant a CPCN if it is necessary for the service, convenience, accommodation, or safety of the public. Because this is a broad grant of authority, the RCA can consider many factors in deciding whether to grant a CPCN.

A CPCN does not create an exclusive right to serve the area covered by the CPCN. Thus other utilities or even non-utilities can request and obtain a CPCN in an area already receiving service from another utility. The RCA may grant multiple certificates and allow competition if it finds that competition is in the public interest. In one case, the RCA noted that the sta-

tute provides the RCA "with comprehensive control over public utilities" and gives the RCA "policymaking authority to determine when and how to implement competition among public utilities" when it is in the public interest to do so. Thus the RCA can issue two or more CPCNs whose holders can then compete for retail customers within the same service area.

On the other hand, the RCA also has authority to deny a CPCN or modify existing CPCNs and restrict competition. Thus it is not necessarily the case that multiple certificates would be available for utilities to compete to serve military installations with energy from off-installation sources.

*Access to Wholesale Electric Markets*

Alaska has not deregulated its power supply markets to allow open access to power markets by retail customers. As noted above, a power supplier must receive a CPCN to deliver power to retail customers, including military installations. Local utilities such as GVEA are not obligated to wheel power from a power supplier to retail customers.

Within Alaska, sales by public utilities to military installations are treated as a retail sale by the utilities. However, it is unclear how the RCA would act if the military were to seek access to wholesale markets. Under Federal jurisdiction and under most other state jurisdictions, military installations are classified as retail customers of public utilities. So Alaska would be unique if the RCA were to grant the military open access to wholesale markets while denying it to other retail customers.

However, GVEA does wheel power generated at FWA to FGA under the terms of a tariff approved by the RCA. According to the RCA, any changes to the tariff or additional wheeling arrangements for GVEA to transport electricity from one military installation to another should be negotiated among the parties and then submitted to the RCA for approval. The RCA would review the terms and conditions to be sure that they were in the public interest. Key to that review would be for the RCA to assure itself that other GVEA ratepayers would not be negatively affected by the wheeling contract. If the wheeling arrangements were in the public interest, the RCA would very likely approve the contract.

If a wheeling contract could not be negotiated with GVEA, the military installations could petition the RCA to adjudicate the issue or it could seek a formal rulemaking on the issue. If the RCA were to find the contract was in

the public interest, it may direct GVEA to enter into the wheeling agreement.

### *Rate Regulation*

The RCA regulates different types of utilities differently depending on the utility's ownership status and type of activity. Although tariff filings need not be docketed for formal review, the RCA can suspend the operation of any tariff filing and can docket rates for a formal review procedure that includes an opportunity for a hearing. The RCA typically reviews utility rates under a full cost-of-service standard. Base rates for each rate class are established pursuant to a formula that considers the cost of service, operation and maintenance costs, applicable taxes, and a "reasonable rate of return" on invested capital. Unlike some state commissions, the RCA does not use extensive substantive rules to govern its rate-setting process.

A regulated utility cannot charge a rate that has not been filed as a tariff with the RCA. The statute requires both rate changes and new tariff filings to be filed with the RCA 45 days before the effective date of the new or changed rate. The RCA has discretion to approve any rate design if there is a reasonable basis to do so and such rates are in the public interest.

## Regulation of Energy Utility Services within the Military Installations

While off-installation energy supplies delivered to the installations have regulatory issues that must be managed, there likely will not be any regulation of energy supplies either generated or distributed within the installations. As noted below, the Department of Defense believes that, except for acquisition of electric commodities, on-installation utility services are not subject to state regulation. While the State of Alaska might take a different position, it appears that significant conflict on this issue is not likely. The primary reason for this is that utility service certificates are nonexclusive in Alaska, as discussed above.

### *Department of Defense Opinion*

In a 4 February 2000, memorandum, the General Counsel of the Department of Defense in addressing the role of state laws and regulations in utility privatization concluded "states may not regulate the Federal government in any respect absent an unequivocal waiver of sovereign immunity." However, the same memorandum concludes that the government has granted a waiver for regulation of the acquisition of electric commodities

excluding distribution or transmission services. This appears to include electricity generated within an installation. The memorandum concludes that "the state may not regulate the Federal government's acquisition of utility services related to the on-base utility system" and, in this context, the Federal government "must comply with state laws and regulations only when it is acquiring the electric commodity."

*Possible State Regulation*

On the off chance that it is determined that the state does have jurisdiction over utility services on the installations, a number of issues might need to be resolved. These should not be difficult, however, because the state likely would grant a CPCN to the entity the Federal government selected to provide utility services on the installation.

Because each installation owns, operates, and maintains its own electric utility system, the installations' utility distribution systems have never been integrated into local utility distribution systems. Existing utility service providers do not actually provide service on the installations and cannot obtain the facilities to do so without permission from the Federal government. In effect, even though a utility provides service to the installation, it is not able to provide the utility service on the installation. Thus a utility with a service area certificate that includes an installation cannot realistically meet the statutory standard to retain a right to serve a particular area. In this circumstance, the RCA can and should conclude that an incumbent certificate holder does not provide service on-installation and cannot do so absent a privatization contract from the installation. The privatized utility system could be treated as a new service territory for which a new certificate must be issued.

In fact, the RCA considered a very similar case when on-installation telephone facilities were privatized in 1980.* In that case, the telephone service area of Elmendorf AFB originally was awarded to two different telephone utilities. Neither had been providing service on the installation because the Air Force operated its own on-installation telephone system. A contract was awarded to one of the utilities to operate part of the on-installation telephone system. The winning utility petitioned the RCA to amend its certificate to include the entire installation. At the end of the

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* Anchorage Telephone Utility, 5 APUC 254, U-80-8 (Order No. 7, February 4, 1983). See Matanuska Telephone Association, Inc., v. Alaska Public Utilities Commission and Anchorage Telephone Utility, No. 3AN-78-8100 Civ. (Alaska Superior Court, 3rd Judicial District, January 4, 1983).

case, the RCA expanded the winning utility's certificate. Significantly, it amended the other utility's certificate to exclude Elmendorf AFB from its service area. The RCA explained that the decertified utility lacked "the ability in the sense of legal capacity or authority to furnish that service; i.e., legal authority that stems from the USAF contracting authorities. That authority, by execution of a contract, was granted" to the winning utility. Although there is no guarantee that the RCA would reach the same conclusion regarding a fact situation similar to Elmendorf's, this case is instructive.*

### Conclusions Regarding Regulatory Constraints and Allowances

Based on the regulatory setting in Alaska, as described above, it appears that only a few regulatory constraints affect energy solutions for installations in the greater Fairbanks area. They are as follows:

1. The installations effectively do not have open access to electric energy supplies in the Anchorage area or other locations that are not within a short distance to the installation. It would be unusual for the RCA to classify the military installations as wholesale customers with access to wholesale power supplies. Most other regulators in the United States classify military installations as large retail customers. However, for the foreseeable future, resolution of this issue would have no effect on power supply options for the installations, because transmission capacity is not available for wholesale supplies to be shipped long distances to the installations included in the GFMC.†
2. All energy supplies delivered to the installations from traditional utilities (e.g., GVEA, AE, and FNG) would be subject to regulation by the RCA.
3. Power supply acquired from an independent power producer would likely be regulated by the RCA.
4. The transmission of any electric energy supply from one installation to another across the GVEA system would need to be negotiated with GVEA and approved by the RCA. It is an open question as to whether GVEA would be obligated to provide this service as part of its CPCN.

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* The RCA has noted that there is a difference in the Federal contracting authority between telephone and other utility services such as those at issue here.

† GVEA currently fully utilizes the Intertie that is used to transport low-cost power from the Anchorage area to Fairbanks. Through this arrangement, the public good in the Fairbanks area is served in the form of lower rates than would otherwise be necessary. Accordingly, the installations would not likely be able to displace GVEA to obtain room on the Intertie to have power transmitted for their own use. GVEA would guard against such a development, and it is highly doubtful that the RCA would grant the installations direct access to wholesale markets that would result in displacement of low-cost power supplies to GVEA and its ratepayers.

5. The military would not be able to sell power off-installation to other entities without becoming a public utility. The military would need to obtain a CPCN and be regulated by the RCA.

A number of apparent allowances would aid in potential energy solutions. They are as follows:

1. If on-installation generation and distribution of energy supplies were privatized, they would not likely be regulated by the RCA. This would include existing and new facilities. The exception is if a utility such as GVEA were to generate or distribute power on-installation. It would likely be included in the RCA's regulation of GVEA's overall operation so that the RCA could be sure that other GVEA customers were not negatively affected by the on-installation operation.
2. Privatization of on-installation utilities could be accomplished through a competitive process. There are two reasons for this. First, the RCA does not appear to have jurisdiction over on-installation utilities. Second, even if the RCA does have jurisdiction, the service area is not necessarily exclusive to one utility. Furthermore, since the military controls access to the installations, only its selected utility service provider would qualify for a CPCN because no other entity would be able to document an ability to serve.
3. As long as it did not serve any other customers, the military could build its own transmission lines to transfer power between installations without RCA regulation.
4. The installations may be able to bypass GVEA and purchase power directly from one or more independent power producers (IPPs). This would require the IPP to connect directly to installation distribution systems and obtain a CPCN from the RCA. The connection would need to be relatively short to be economical and, therefore, would require the IPP to locate either on or close to the installation to which power would be sold. In effect, this would provide the military with open access to power supplies generated on or near the installations. However, it is unknown how the RCA might react if GVEA intervened against the CPCN application.
5. When and if natural gas transmission is developed to Fairbanks, the installations likely would have access to wholesale supplies. Although there is no precedent for this in Alaska, such open access to wholesale markets exists in other states. Furthermore, as long as it did not conflict with the public interest, access likely would be allowed by the RCA. Delivery to the installations through a utility serving the general public likely would be subject to RCA regulation, however.

6. The installations would be able to buy steam and natural gas from an off-installation supplier without regulation if that supplier had fewer than 10 customers.

## Fuels in Interior Alaska

On the basis of identified resources, coal is the predominant fuel used in Alaska, followed by oil, and then by natural gas (Figure 7).

### Coal

Usibelli Coal Mine, Inc. (UCM), operates a coal mine near Healy, AK, about 80 air miles south-southwest of Fairbanks. This is the only coal mining operation in Alaska and provides coal to GVEA's Healy Coal Plant, Clear Air Force Base, Aurora Energy's Chena Power Plant, the University of Alaska–Fairbanks Power Plant, FWA, and EAFB.

There are proven UCM coal reserves of 200 million tons; at current extraction rates, this is a 100-year supply. Total Alaska coal resources have been estimated at 171 billion tons, so more reserves could be proven, but there is no reason to do so at this time. The coal grade is sub-bituminous C, and UCM expects the quality to remain reasonably constant (7,800 British thermal units per pound [Btu/lb]) because the coal is coming from the same seams UCM has historically mined, just in different locations.

UCM recently started a new mine, the Two Bull Ridge Mine, and is working through the "outcropping" coal before it gets to the main seam. Once the outcropping coal is mined, the seam should be more consistent with 7,800 to 8,000 Btu/lb coal. This mine area has 42 million tons of reserves. About 2 million tons have been mined, with 40 million tons remaining. The current extraction rate is about 1.2 million tons per year (tpy), implying that the mine has 30+ years of expected life. This mine is expected to be the primary source of coal delivered to FWA and EAFB.

UCM is closing out the Gold Run Mine, which has about 7 to 8 years of remaining life. UCM has permits in hand for the new Rosalie Mine, which has 50 million tons of permitted coal. There is also the Emma Creek deposit, which has 50 to 75 million tons of coal with a less than 2:1 dirt-to-coal ratio. Initial tests indicate a heat content of 7,200 Btu/lb; UCM expects further testing to indicate a heat content up to 7,900 Btu/lb.

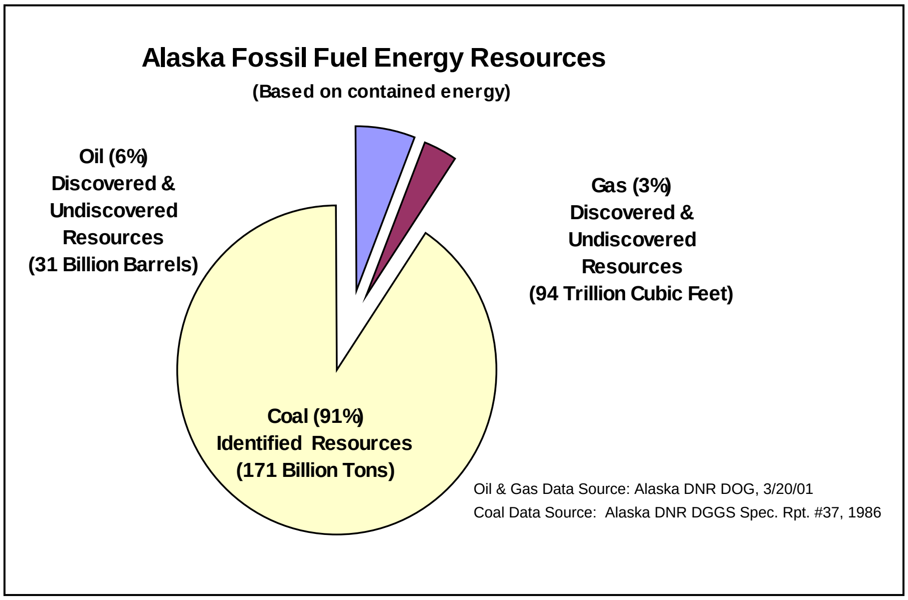



Figure 7. Alaska fossil fuel energy resources.

The Usibelli coal is the lowest-sulfur coal in the United States. In the past, the coal has averaged 0.2 percent sulfur content (by weight). The Two Bull Ridge seams are ranging a little higher (0.4 to 0.5 percent), and some of the coal has been as high as 1 percent sulfur. The coal characteristics (ash content, moisture content, chemical analysis) are not expected to change.

At the mine, Usibelli screens the coal to be delivered to FWA and EAFB to remove most of the ¼-in. "fines."

The coal is transported to FWA and EAFB via the Alaska Railroad, which is owned by the State of Alaska. A single rail line runs from Healy to the Fairbanks area, which represents a single-contingency interruption in fuel deliveries, although coal could also be trucked, if necessary. The mitigation has been to have significant onsite coal storage at both FWA and EAFB.

UCM has a 5-year contract with the Defense Energy Support Center (DESC) to provide a total of up to 1.87 million tons of coal to FWA and EAFB over the life of the contract. The contract's effective date is 26 July 2002.

Table 4 lists the contract specifications for coal characteristics for deliveries to FWA and EAFB. Table 5 lists the estimated monthly amounts of coal to be delivered under the contract.

Table 4. Contract specifications for coal deliveries to FWA and EAFB.

| Requirement | Delivered Coal Characteristics | | |
|---|---|---|---|
| | Units | Monthly Average | Per Shipment |
| Moisture, as received | percent max. | 27.0% | 30.0% |
| Volatile matter, dry | percent | | |
| Ash, dry | percent max. | 9.0% | 13.0% |
| Sulfur, dry | percent max. | 0.4% | 0.4% |
| Heating value, dry | Btu/lb | 10,822 | 10,714 |
| Heating value, as received | Btu/lb | 7,900 | 7,500 |
| Screen size | | Max. percent retained | |
| R.H. screen | 4 in. | 0.0% | N/A |
| | | Max. percent passing through | |
| R.H. screen | ¼ in. | 15.0% | 20.0% |

Table 5. Estimated monthly coal deliveries to FWA and EAFB.

| | FWA Est. Monthly Amount (Tons) | EAFB Est. Monthly Amount (Tons) |
|---|---|---|
| October | 18,000 | 18,000 |
| November | 20,000 | 18,000 |
| December | 20,000 | 21,000 |
| January | 23,000 | 21,000 |
| February | 20,000 | 17,000 |
| March | 19,000 | 17,000 |
| April | 15,000 | 14,000 |
| May | 14,000 | 13,000 |
| June | 11,000 | 10,000 |
| July | 11,000 | 10,000 |
| August | 11,000 | 11,000 |
| September | 13,000 | 13,000 |
| Total Annual | 195,000 | 183,000 |
| Max. Monthly Amount (tons) | 28,000 | 24,000 |
| 5-Year Max. Amount to be Delivered | 975,000 | 915,000 |

The 5-year price for delivered coal transported from Healy to the installations over the Alaska Railroad is $50.30 per ton for FWA and $51.05 per ton for EAFB. Under the contract, a price adjustment occurs if and when the heat content of the coal falls below 7,600 Btu/lb. At the expected average heat content of 7,800 Btu/lb, the cost of delivered coal is $3.18 per MMBtu for FWA and $3.23 for EAFB.

UCM has proposed developing a 200-MW circulating fluid-bed coal-fired project at the Emma Creek deposit. The project, as described in UCM

promotional material, would supply coal at a cost of $1 per MMBtu. This is considerably less than the price paid for coal delivered to FWA and EAFB.

It is our understanding that Federal regulations limit the contract term to no more than 5 years. A better coal price most likely would be obtained if a longer-term contract were negotiated. This should be pursued with DESC.

### Oil

The Trans-Alaska Pipeline System runs to the north of Fairbanks, entering the area from the northwest and turning south to the City of North Pole, which is about 12 miles southeast of Fairbanks. At North Pole, two refineries (Williams Alaska and PetroStar) take crude oil from the pipeline, refine the wanted products, and then return the residual oil back to the pipeline. The refineries produce gasoline, naphtha, jet fuel, heating fuel, diesel fuel, heavy atmospheric gas oil, and asphalt for supply to local and international markets. GVEA owns the pipelines that take oil to and from the TAPS for the two refineries.

TAPS flow levels are declining. North Slope oilfield crude production peaked in the late 1980s at more than 2 million barrels (MMbbl) per day. It currently runs at about 1 MMbbl per day and is projected to decline to about 723,000 barrels (bbl) per day by 2020 and 509,000 bbl per day by 2025 (Figure 8).

Alyeska Pipeline Service Company (Alyeska) operates the TAPS as agent for the owners. At various locations along the TAPS, pump stations keep the oil moving. Alyeska is considering converting several of these pump stations from oil-fired CT power to electrical power purchased from GVEA. One of these pump stations, PS 9, is adjacent to the GMD area near FGA and, if electrified, represents a 15- to 20-MW load.

The price paid for oil products removed from the pipeline is determined under an arrangement known as the Quality Bank. The Federal Energy Regulatory Commission (FERC) approves the pricing methodology used by the Quality Bank. The Quality Bank compares the value of the diverted portion of the common oil stream to that of the returned stream, charging the refiners and compensating the other shippers for the common stream's reduction in value caused by the refineries' removal of products. The Quality Bank also makes monetary adjustments among the shippers to compensate for the commingling of differing qualities of crude oil.

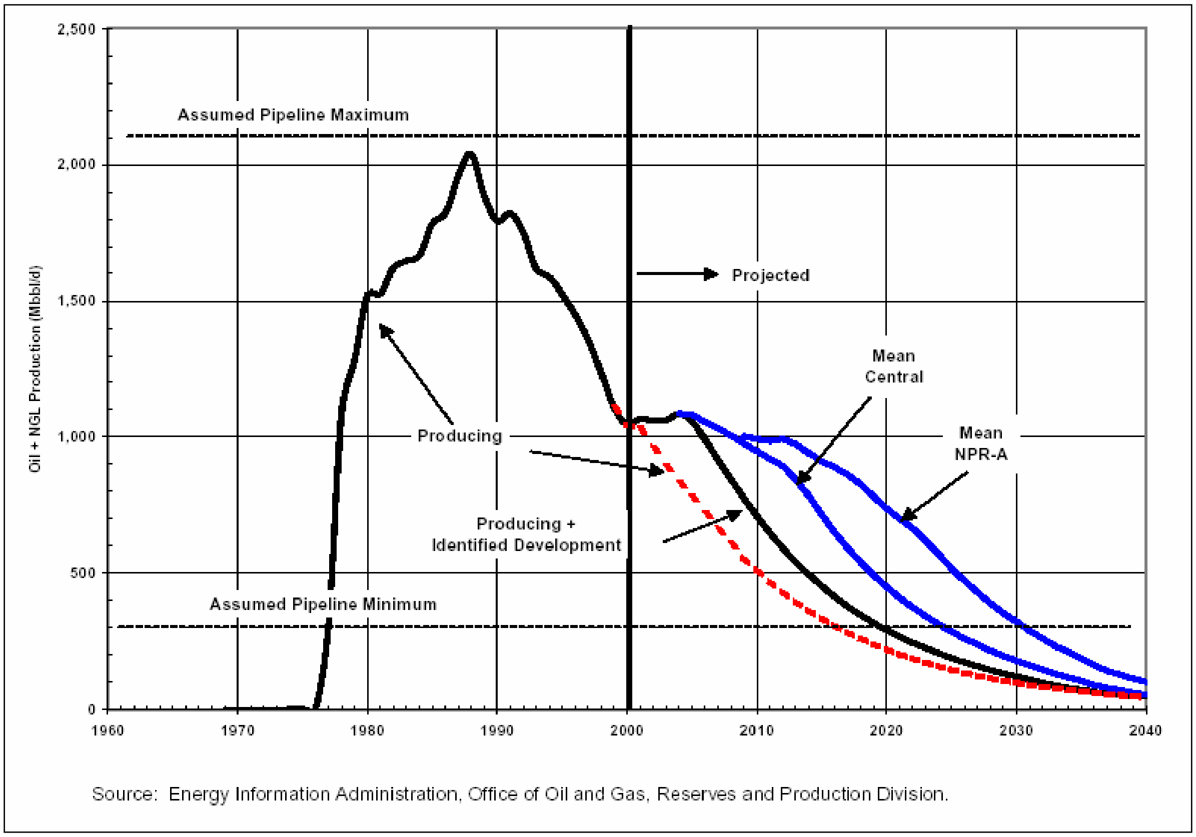



Figure 8. Alaska north slope production history and mean estimates of undiscovered resources.

A number of methods are available to assign value to individual streams: the gravity methodology based on the American Petroleum Institute (API) scale; the assay methodology, which divides each stream into eight components and values each component; and the distillate cut/residual cut methodology, which places a value on these two cuts.

The methodology used to determine the prices paid for products removed at North Pole has been subject to dispute before FERC and in the courts. While this creates some uncertainty as to the cost of North Pole products, it is reasonable to assume that those prices will reflect oil market prices on the West Coast of the United States.

Naphtha represents from 17.5 to 20.3 percent of the pipeline oil stream. GVEA intends to use naphtha as the fuel for its proposed 120-MW North Pole expansion power plant. Our estimates of the availability of naphtha over the next 25 to 30 years indicate an ample supply for 800 to 1,100 MW of generation.

The TAPS is a single pipeline; any interruption in flow represents a lack of fuel supply for the Fairbanks area. Historically, this has not been a significant issue, but it does represent a security concern.

### Natural Gas/LNG

*Fairbanks Natural Gas*

FNG trucks liquefied natural gas (LNG) to Fairbanks from the Cook Inlet (Anchorage), AK, area in 9,000-gal tanker trucks. FNG offers natural gas service in parts of Fairbanks as an alternative to fuel oil heat. Its natural gas distribution system runs up to the western boundary of FWA. FNG has an existing customer base of about 560, about 40 percent of which are residential customers and 60 percent commercial/industrial customers. Annual sales are approximately 400,000 million cubic feet (mcf).

FNG has expressed an interest in providing LNG/natural gas service to FWA, either by extending its existing system onto the base to service individual housing units and buildings or by constructing a separate on-base system (vaporization, storage, distribution) to serve heating loads. This could be an appropriate solution for those facilities not served by the existing FWA utilidor system. To provide service on FWA, FNG needs to obtain regulatory approval because FWA is outside of its existing service area. Supplying fuel to the FWA CHPP would represent an order-of-magnitude increase in FNG's business.

FNG is approved to offer natural gas service in the Fairbanks area only. It does not have regulatory approval for service elsewhere; this approval likely could be obtained if pursued.

FNG also expressed interest in providing service to EAFB and FGA, both of which would require complete new infrastructure to provide service.

FNG's current tariff for Large Commercial customers has a $50 a month customer charge and a commodity charge of $8.26 per thousand cu ft. Assuming a delivered heat content of 1,000 Btu per cubic foot, the commodity cost is $8.26 per MMBtu.

*Alaska Natural Gas Transportation System (ANGTS)*

There is a great deal of discussion and activity associated with the possibility of a natural gas pipeline, ANGTS, transporting North Slope natural gas

to the Fairbanks area, most likely North Pole. The pipeline likely would continue south to almost Delta Junction, where it would turn eastward. There are 32 to 38 trillion cu ft of recoverable gas under the North Slope.

In January 2004, two separate applications were filed with the State of Alaska Department of Revenue under the Stranded Gas Development Act for a natural gas pipeline from the North Slope through Alaska to markets in Canada and the Lower 48. The applications are for authority to negotiate tax and financial terms with the state to facilitate the transportation of stranded Alaska natural gas.

The application from a group made up of Conoco Phillips, BP, and ExxonMobil was accepted on 23 January 2004. The application projected a 9-year lead time to "first gas" once the Stranded Gas Act agreement is established. The earliest "first gas" date would be the end of 2012.

The application from a second group made up of MidAmerican Holdings Co. and MEHC Alaska Gas Transmission Company, Pacific Star Energy, a consortium including 12 Native corporations, and Cook Inlet Regional, Inc. (an Alaska Native corporation) was accepted on 28 January 2004. This group's application anticipated an in-service date of 31 December 2010. On 25 March 2004, this group announced it was withdrawing its application, citing the State's unwillingness to give it a 5-year exclusive deal to develop the pipeline.

On 27 February 2004, a third group, the Alaska Gasline Port Authority, which is a joint effort of the City of Valdez, the Fairbanks North Star Borough, and the North Slope Borough, filed an application. The State is evaluating whether the authority is a qualified applicant. Until that is determined, the application will not be accepted. On 25 March 2004, the North Slope Borough announced it was withdrawing from the group. The effect of this withdrawal on the application is not known at this time.

The price of natural gas in Fairbanks likely would reflect the market value of the gas in the upper U.S. Midwest adjusted for transportation costs. If this were the case, the price of the ANGTS gas would reflect any volatility in the U.S. natural gas market.

Security of the supply would be similar to that for the TAPS oil line: a single supply line that if disrupted for a period of time would result in no fuel supply. Fairbanks area storage would mitigate this concern.

*Nenana Area Natural Gas*

Ongoing efforts are being made to discover and prove natural gas resources in the Nenana area, about 50 miles southwest of Fairbanks. The probable gas reserves have been estimated at 3 trillion cu ft. At this time, it is too early to speculate on the outcome of these efforts. However, the Nenana field might be a source of natural gas for the Fairbanks area sooner than the ANGTS. The size of the field is unlikely to support the cost of a pipeline to export the gas out of Interior Alaska and, in this sense, might be considered a stranded supply.

If exploration efforts are successful and adequate gas reserves are proven, the market for this gas may be power generation in the Nenana area using the existing GVEA transmission system to transmit the power to end users. If this were the case, it would provide competitive pressure on other fuel sources for electricity generation.

If a North Slope gas pipeline is constructed, it may be economical to build an approximately 50-mile-long pipeline to interconnect this field and allow export.

### Fuels Security

The issue of security is associated with each type of fuel and can be subdivided into the following categories:

- Fuel source security
- Fuel transportation and delivery security
- Generation (heat and power) security
- Heat and power delivery security.

*Fuel Source Security*

As previously discussed, the main fuels in Interior Alaska are coal, oil (and oil distillates), LNG, and, potentially, natural gas, recognizing that LNG is in the area now on a small scale. All of these fuels are produced in Alaska. With the exception of coal, they are imported from either the North Slope or the Anchorage area.

<u>Coal</u>

UCM operates more than one mine, and the coal quality is reasonably uniform from all mines. Coal can be stored onsite reasonably easily and inexpensively, as is now done at FWA and EAFB. At current rates of extraction,

there are more than 100 years of proven coal reserves in the Healy area. Additional reserves can be proven relatively easily. Disruption of coal supplies for more than 60 days is reasonably unlikely. Coal is a secure fuel.

#### Oil and Oil Distillates

North Slope oil taken off the TAPS at North Pole has been a reliable fuel. Production at the North Slope is projected to continue beyond 2030, but at ever-decreasing levels. Oil storage is not difficult, but is relatively expensive, especially to maintain large volumes sufficient to protect against 60-day interruptions. Compared to coal, oil is a less secure fuel.

#### LNG

FNG imports LNG from a supply in the Anchorage area (Wasilla) to Fairbanks by tanker truck. Cook Inlet gas supplies are declining and becoming more expensive. New gas fields are expected to be found and developed, but will produce gas at a higher cost than the existing fields. LNG can be easily stored, but the facilities are expensive and represent a potential security risk in and of themselves. The quantities being imported by FNG are very small compared to power plant needs. The North Slope represents another potential source for LNG that could be trucked into the Fairbanks area. Compared to coal and oil, LNG is a less secure fuel.

#### Natural Gas

A reasonably abundant supply of natural gas in the Fairbanks area depends on a new natural gas pipeline for North Slope natural gas. Storage of natural gas is expensive. Typically, the gas is stored at high pressure in spheres or natural caverns with leak-tight characteristics. From a fuel security perspective, natural gas would be comparable to oil.

### *Fuel Transportation Security*

#### Coal

Coal is transported from the Healy area to Fairbanks via the Alaska Railroad. While the rail route is exposed to single-contingency outages along its length, repair and restoration of service should be relatively straightforward. In this sense, coal is a secure fuel.

#### Oil, Oil Distillates, Natural Gas

The TAPS is a single pipeline and is exposed to a single-contingency outage along its entire length. Interruptions in oil supply to the Fairbanks

area have occurred due to leaks in the TAPS north of Fairbanks. Furthermore, once the fuel is removed from the pipeline, it needs to be distributed to points of use. This distribution system, whether by truck or pipeline, presents an additional security risk. Oil and oil distillate supplies depend on the security of the North Pole refineries. Presumably, a natural gas pipeline would be a single line and would have the same exposure to risk. For these reasons, oil and natural gas are less secure than coal. Natural gas may be somewhat more secure than oil.

*Generation (Heat, Power) Security*

For all of the fuels, once they are delivered within the fence at an installation, their use and the generation of either heat or power is considered secure. Onsite storage is much more secure with coal than it is with oil, LNG, or natural gas. In this sense, coal is slightly more secure than the other fuels.

If heat or power generation takes place outside the fence, it is less secure than inside the fence unless the facility has the same degree of security protection as the installations. In this sense there is no security difference among the fuels.

*Distribution Security*

Distribution of heat and power within an installation's fence is considered secure, and there is no real security difference among the fuels. If the heat or power plant is located outside the fence, the fuels may have a different level of security compared to the installations.

*Fuel Cost Stability/Volatility*

Figure 9 indicates the historical prices for coal, petroleum, and natural gas. It can be seen that coal prices have declined, petroleum prices have experienced periods of high prices and appear to be trending higher, and natural gas prices are more volatile in recent years than either coal or oil. Recently, the Lower 48 has seen a significant increase in the use of natural gas for electricity generation.

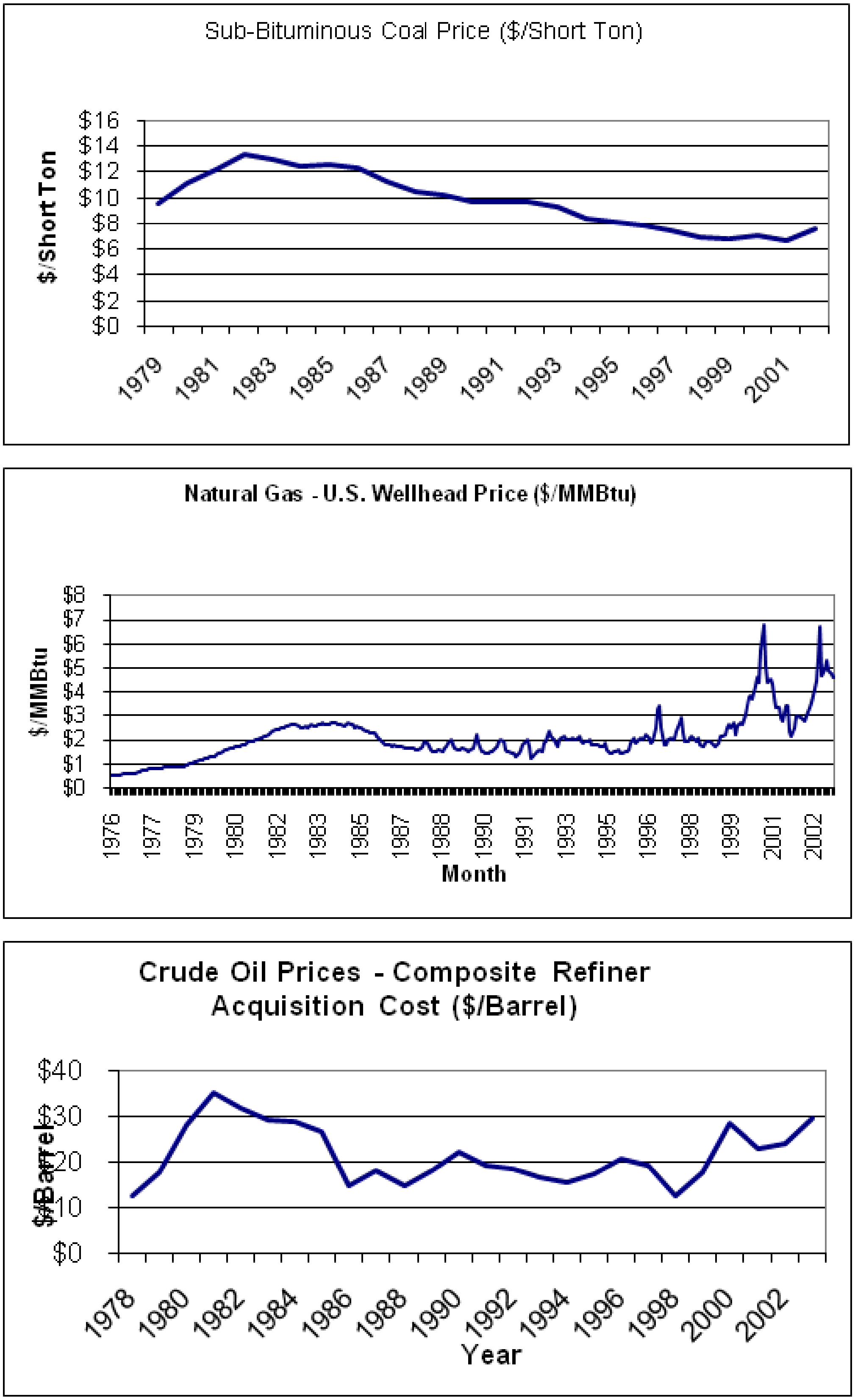



Figure 9. Historical U.S. fuel prices (source: Energy Information Administration).

# 4 Golden Valley Electric Association

GVEA is the electric utility serving the greater Fairbanks area. It is a non-profit rural electric cooperative governed by an elected board of directors. It is regulated by the Regulatory Commission of Alaska (RCA) and holds an RCA Certificate of Public Convenience and Necessity (CPCN) for its service area.

Any arrangements GVEA makes with the GFMC installations are subject to RCA review and approval. The RCA review is intended to ascertain whether or not the arrangements adversely affect GVEA's other customers. If the RCA finds that an arrangement adversely affects other customers, it can withhold its approval.

GVEA's historical system peak demand is 184.5 MW with annual sales of more than a billion kWh. It operates and maintains 2,566 miles of transmission and distribution lines and 31 substations, and is interconnected with FWA, EAFB, FGA, GMD, and electric utilities in south central Alaska via the Railbelt Intertie (Intertie) transmission line. The Intertie allows exchange of generation reserves among Railbelt utilities and substantially increases system reliability for Railbelt communities. The Intertie allows GVEA to augment its generation capacity with an additional 70 MW of imported power. GVEA has 228 MW of generating capability at five generating facilities.

GVEA recently installed a 27-MW battery electric storage system (BESS) in Fairbanks to serve as a backup to the Intertie. When Intertie interruptions occur, the BESS provides backup power supply until GVEA can bring replacement generation online. The BESS also smoothes out many of the transient conditions GVEA experiences in its system.

## GVEA Power Supply

Table 6 lists existing power generation resources in Interior Alaska that are interconnected to the GVEA system, including those at FWA and EAFB. Note that the FWA and EAFB generation is not available to GVEA, nor is the University of Alaska–Fairbanks (UAF) generation or the FGA and GMD backup generation, which are not shown.

The GVEA resources include GVEA's 16.9 percent purchaser obligation in the Bradley Lake Hydroelectric Project.

It can be seen that GVEA's resources are predominantly oil-fired, and the units are 25 years old or more. With the exceptions of Bradley Lake hydropower and Healy coal, all of GVEA's generation is located in the Fairbanks/North Pole area.

GVEA is obligated to annually purchase 120,000 MWh from AE on a take-or-pay basis (about 11 percent of GVEA's annual sales). GVEA can also purchase additional energy (in excess of 120,000 MWh) if it requests the energy from AE and AE is able to provide it without incurring additional startup costs.

Table 7 lists approximate heat rates and fuel costs. The information is not intended to be definitive, but rather to give guidance as to the approximate fuel cost to generate an incremental kWh of electricity. It can be seen that Bradley Lake is the lowest-cost resource for GVEA; being a hydroelectric project, it has no incremental fuel cost. The Healy 1 Coal Plant is GVEA's next lowest incremental cost resource, followed by energy purchases from AE. The incremental fuel cost of the other GVEA resources are 4.5 cents per kWh or higher. As discussed below, GVEA is able to purchase energy from the Anchorage area when it is economical to do so. Note that the fuel cost of FWA and EAFB generation is above 4.5 cents per kWh. From an integrated "system dispatch" perspective, the FWA and EAFB generation is high-cost generation and, to the extent lower cost generation is available, would most likely not be operated except during peak hours and emergencies.

GVEA has no generation southeast of North Pole where EAFB, FGA, and GMD are located, and it has no plans to locate generation there, perhaps because there is no cost-effective fuel supply available south of North Pole. It is less expensive for GVEA to transmit electricity than to move fuel to the area by truck. (It should be noted that the Alaska Railroad terminates at EAFB and does not go any farther toward Delta Junction.)

Table 6. Existing power generation—GVEA, Aurora Energy, FWA, and EAFB.

| Company & Plant(s) | Unit ID | Generator Nameplate Capacity (MW) | Net Summer Capability (MW) | Net Winter Capability (MW) | Unit Type | Fuel | Year of Commercial Operation | Status | Approx. Heat Rate | Approx. Fuel Cost $/MMBtu | Approx. Fuel Cost $/kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Golden Valley Electric Assoc | | 240.4 | 214.4 | 248 | | | | | | | |
| Fairbanks | GT1 | 17.6 | 16.3 | 18.0 | CT | F02 | 1971 | | 12,500 | $4.50 | $0.0563 |
| | GT2 | 17.6 | 16.3 | 18.0 | CT | F02 | 1972 | | 12,500 | $4.50 | $0.0563 |
| | Dsl5 | 2.6 | 2.6 | 2.6 | IC | F02 | 1970 | | 10,000 | $4.50 | $0.0450 |
| | Dsl6 | 2.6 | 2.6 | 2.6 | IC | F02 | 1970 | | 10,000 | $4.50 | $0.0450 |
| | GT6 | 23.1 | 23.1 | 29.3 | CT | F02 | 1976 | | 12,000 | $4.50 | $0.0540 |
| Healy | Dsl1 | 2.5 | 2.5 | 2.5 | IC | F02 | 1967 | | 10,000 | $5.00 | $0.0500 |
| | 1 | 25.0 | 25.0 | 25.0 | ST | Coal | 1967 | | 14,000 | $1.25 | $0.0175 |
| North Pole | 1 | 64.7 | 53.0 | 65.0 | CT | F04 | 1976 | | 10,000 | $4.50 | $0.0450 |
| | 2 | 64.7 | 53.0 | 65.0 | CT | F04 | 1977 | | 10,000 | $4.50 | $0.0450 |
| Bradley Lake (near Homer, AK) | 1&2 | 20 | 20.0 | 20.0 | Hydro | H20 | 1991 | | - | N/A | $- |
| Aurora Energy, LLC | | 33.8 | 33.8 | 35.5 | | | | | | | |
| Chena (FNSB) | 1 | 5.0 | 5.0 | 5.0 | ST | Coal | 1954 | | 15,000 | $2.25 | $0.0338 |
| | 2 | 2.0 | 2.0 | 2.0 | ST | Coal | 1951 | | 15,000 | $2.25 | $0.0338 |
| | 3 | 1.5 | 1.5 | 1.5 | ST | Coal | 1951 | Moth-balled | - | - | - |
| | 4 | 5.3 | 5.3 | 7.0 | CT | F02 | 1963 | Moth-balled | - | - | - |
| | 5 | 20.0 | 20.0 | 20.0 | ST | Coal | 1970 | | 14,000 | $2.25 | $0.0315 |
| Fort Wainwright | | 20.0 | 20.0 | 20.0 | | | | | | | |
| Central Heat & Power Plant | 1 | 5.0 | 5.0 | 5.0 | ST | Coal | 1952 | | 15,000 | $3.18 | $0.0477 |
| | 3 | 5.0 | 5.0 | 5.0 | ST | Coal | 1952 | | 15,000 | $3.18 | $0.0477 |
| | 4 | 5.0 | 5.0 | 5.0 | ST | Coal | 1952 | | 15,000 | $3.18 | $0.0477 |
| | 5 | 5.0 | 5.0 | 5.0 | ST | Coal | 1952 | | 15,000 | $3.18 | $0.0477 |

| Company & Plant(s) | Unit ID | Generator Nameplate Capacity (MW) | Net Summer Capability (MW) | Net Winter Capability (MW) | Unit Type | Fuel | Year of Commercial Operation | Status | Approx. Heat Rate | Approx. Fuel Cost $/MMBtu | Approx. Fuel Cost $/kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Eielson Air Force Base | | 33.5 | 32.8 | 33.5 | | | | | | | |
| Central Heat & Power Plant | 1 | 2.5 | 2.5 | 2.5 | ST | Coal | 1952 | | 15,000 | $3.23 | $0.0485 |
| | 2 | 2.5 | 1.8 | 2.5 | ST | Coal | 1952 | | 15,000 | $3.23 | $0.0485 |
| | 3 | 5.0 | 5.0 | 5.0 | ST | Coal | 1956 | | 15,000 | $3.23 | $0.0485 |
| | 4 | 5.0 | 5.0 | 5.0 | ST | Coal | 1969 | | 15,000 | $3.23 | $0.0485 |
| | 5 | 10.0 | 10.0 | 10.0 | ST | Coal | 1988 | | 15,000 | $3.23 | $0.0485 |
| | Dsl1 | 2.5 | 2.5 | 2.5 | IC | F02 | | | 10,000 | $4.50 | $0.04505 |
| | Dsl2,3, 4,5 | 6.0 | 6.0 | 6.0 | IC | F02 | | | 10,000 | $4.50 | $0.0450 |

Source: GVEA, Energy Information Administration, Railbelt Utility Group.

GVEA purchases natural gas–fueled electric energy from the Anchorage area over the Intertie. This power is less expensive than GVEA's oil-fired generation (economy energy). The Intertie has a capacity limitation south of Healy. Apart from Bradley Lake's power (20 MW), GVEA is able to import 50 MW of economy energy from the Anchorage area. Reinforcement of the southern Intertie (south of Healy) will increase the Intertie's capacity and allow GVEA to import more economy energy. From Healy north, the Intertie has a capacity of 140 MW. Bradley Lake hydropower and Healy coal represent 45 MW of this capacity.

The Healy Clean Coal Project (HCCP),* if brought online, would use another 50 MW of this capacity, leaving 55 MW available for import of economy energy. Because HCCP is essentially a mine-mouth project, its incremental fuel cost can be expected to make it a low-cost resource. As a result, if completed, HCCP would be a base-load resource. It is our understanding that an agreement allowing for reconfiguration of the plant may occur in the next 1 or 2 years.

GVEA intends to add generation at North Pole (the North Pole Expansion [NPE]). Development of the NPE is significantly affected by decisions about the HCCP. Eventually the NPE could consist of two 45-MW GE LM6000 CTs (CT) burning naphtha from the Williams Refinery† and a 30-MW STG, allowing the plant to operate in combined-cycle mode with a heat rate of 7,000 Btus per kilowatt-hour (Btu/kWh). In simple cycle mode (CT only), the heat rate is expected to be 9,000 Btu/kWh. It is our understanding that the first phase of development for the NPE will be a single CT without heat recovery for peaking operation. Based on current naphtha prices of about $0.62/gal ($5.65 per MMBtu), combined-cycle operation results in a fuel cost per kWh of just under 4 cents. This incremental fuel cost makes the NPE unattractive for meeting base loads. Its primary use in the near future likely would be during peaks, perhaps during intermediate load levels, and during outages of other resources. If the

* The HCCP, located at Healy, AK, was developed and constructed under a U.S. Department of Energy demonstration program for clean coal technologies. It employed an entrained combustion (slagging) system coupled with a boiler to obtain low $NO_x$ levels and act as a limestone calciner and first-stage $SO_2$ remover. The plant included a single-spray dryer absorber vessel for second-stage $SO_2$ removal, a baghouse for third-stage $SO_2$ and particulate removal, and a lime activation system to recover unused reagent from particulate collected in the baghouse. The State of Alaska owns the HCCP. The project was completed in 1991 and has been mothballed since because it did not operate as expected. There have been ongoing discussions between the State and GVEA about reconfiguring the project to use a more conventional, proven technology.

† In November 2003, Williams sold the refinery to Flint Hills Resources subject to Federal Trade Commission approval.

State of Alaska's future ANS crude oil price projections of $24/bbl are accurate, then NPE's fuel cost per kWh would be close to $0.035/kWh, which makes it attractive for meeting base loads.

The two largest (single-shaft) generation units on the GVEA system are 65 MW. From a reliability standpoint, if one of these units is operating and trips off line, it takes a minimum of three or four other units to replace the lost generation. This creates a significant spinning reserve burden. GVEA has addressed this with procedures in place to shed load if necessary. The BESS provides an immediate backup of 27 MW for up to 15 minutes, sufficient time to get backup generation online. Bradley Lake also provides cost-effective spinning reserves and is used to do that under an agreement with other Railbelt generating utilities.

New GVEA generation units should be no larger than 65 MW to avoid compounding the problem, but should be as large as possible to achieve an economy of scale. GVEA's NPE will have 45-MW simple cycle units (60 MW in combined cycle), which is a good size from a reliability/reserves perspective.

## GVEA Electrical Transmission System

As previously discussed, the GVEA system is interconnected to the Anchorage area over the Intertie. Historically, the Intertie has been a single-circuit line which, when tripped out of service, isolates GVEA. Power is almost always flowing into the GVEA system because of the import of Bradley Lake hydropower, Healy coal, and economy energy from the Anchorage area. This exposure forces GVEA to maintain sufficient Fairbanks generation to be able to meet its loads without reliance on the Intertie.

The GVEA transmission system is a combination of 138-kilovolt (kV) and 69-kV lines (Figure 10). Two GVEA lines run north from Healy to Fairbanks, with a total transmission capacity of 140 MW. South of Healy, the Southern Intertie is a single circuit that is scheduled for upgrade in the future.

In the Fairbanks/North Pole area, GVEA has a "grid" of 138-kV and 69-kV lines and substations that provide redundancy, allowing GVEA to isolate portions of its system and maintain service to all customers. At the distribution-system level, GVEA generally has the ability to serve all customers from adjacent substations if a particular substation is out of service.

South of North Pole, where EAFB, FGA, and GMD are located, GVEA has a single transmission line. The first section of the line from North Pole to the Carney Substation located near TAPS Pump Station 8 east of EAFB is 69 kV. The rest of the line to FGA and GMD is operated at 138 kV. GVEA has undertaken an environmental assessment to build a new 138-kV line segment from its North Pole Substation to its Carney Substation. This will provide a second circuit to the Carney Substation, improve system reliability, and reduce losses for power flowing south.

## Historical Outages

GVEA groups its outages into four broad categories:

- Category A: Power Supply
- Category B: Extreme Storm
- Category C: Prearranged
- Category D: Other

Category A and B outages tend to be broad, affecting many customers. Category C outages usually will be limited in scope and duration. Category D outages are local in nature, affecting fewer customers, but the duration may be relatively long if an equipment failure is involved.

Examination of GVEA outage records from 1999 through 2003 shows that its system-wide average reliability for providing power is 99.97 percent, a level consistent with utilities in the Lower 48 states. Over the period examined, there is a trend toward improved reliability. However, the period examined is too short to draw any conclusions regarding trends (Table 7).

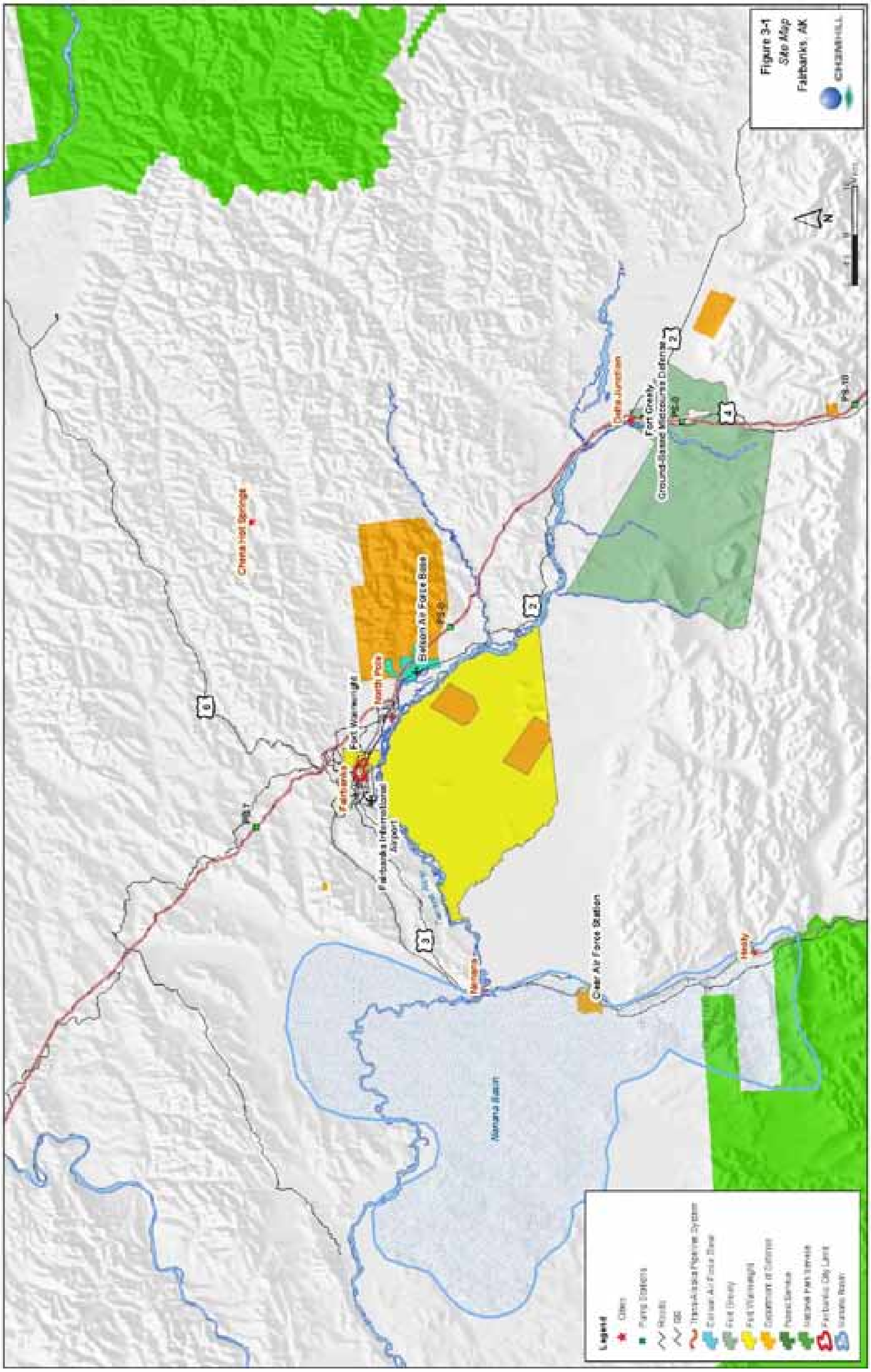



Figure 10. Geographic location of principal facilities in transmission system.

Table 7. GVEA transmission system outages by category.

| Category | | Annual Average—January 1999 through September 2003 | | | |
|---|---|---|---|---|---|
| | | No. of Outages | Customers Affected | Customer Hours | Minutes per Customer |
| *Category A: Power Supply* | | | | | |
| | Unit Trip | 17 | 114,625 | 10,240.90 | |
| | Transmission | 15 | 106,212 | 23,406.95 | |
| | Recloser | 19 | 12,847 | 401.33 | |
| | Silos Event | 21 | 110,705 | 7,411.63 | |
| | Subtotal | 21 | 143,602 | 34,547.26 | 56.53 |
| *Category B: Extreme Storm* | | | | | |
| | Wind | 79 | 60,789 | 10,363.13 | |
| | Snow | 49 | 20,907 | 4,683.90 | |
| | Rain | 4 | 678 | 92.18 | |
| | Flood/Lightning | 18 | 1,913 | 1,876.65 | |
| | Subtotal | 106 | 57,755 | 16,925.98 | 37.91 |
| *Category C: Prearranged* | | | | | |
| | Planned | 226 | 19,415 | 8,879.19 | |
| | Subtotal | 197 | 10,582 | 8,676.18 | 14.01 |
| *Category D: Other* | | | | | |
| | Trees | 132 | 41,646 | 8,918.83 | |
| | Animals | 271 | 46,700 | 3,659.80 | |
| | Teardown | 56 | 11,821 | 4,747.96 | |
| | Equipment | 175 | 43,144 | 20,802.77 | |
| | Subtotal | 531 | 30,653 | 37,591.37 | 61.79 |
| *Total Outages* | | *856* | *187,585* | *97,670.61* | *160.3068* |
| Avg. Number of Customers | | | 38,633.47 | | |
| | Hours per Customer | | | 2.672 | |
| | Interruptions per Customer | | | 5.140 | |
| | Minutes per Interruption | | | 33.302 | |
| *Percent of time* | | | | | *0.000304998* |
| *Percent of time with Power* | | | | | *99.970%* |

GVEA transmission system outages affecting GFMC installations are shown in Table 8. Although transmission system outages are relatively few, they can last several hours. A recent prolonged outage occurred on 16 November 2003, when temperatures were about -35 °F. This outage affected both FGA and GMD.

Table 8. Description of GVEA transmission system outages affecting GFMC installations (1997-2003).

| Date | Description | Duration (minutes) | Installation Affected | | |
|---|---|---|---|---|---|
| | | | FWA | EAFB | FGA/ GMD |
| 30 July 1997 | Healy trips, system out of step | 5 | X | X | X |
| 16 July 1998 | Carney Substation-Jarvis Creek Substation 138 kV line, lightning strike | 1 | | | X |
| 1 September 1998 | Carney Substation, 138 kV fault | 56 | | X | X |
| 13 May 1999 | Carney Substation-Jarvis Creek Substation 138 kV line, lightning strike | 1 | | | X |
| 17 July 1999 | Highway Park Substation-Carney Substation 69 kV line, pole failure | 230 | | X | X |
| 18 June 2001 | North Pole Power Plant 1, Healy Power Plant, Chena 5 all trip | 10 | X | X | X |
| 7 June 2002 | North Pole Power Plant tripped off by lightning | 47 | X | X | X |
| 12 May 2003 | Johnson Road Substation recloser fails to clear fault | 21 | | X | X |
| 16 November 2003 | Jarvis Creek Substation blown fuse, Carney Substation breaker failure | 360 | | | X |
| 2,300 days | Days observed | 731 | 62 | 369 | 731 |
| | Reliability (percent of time with power)* | 0.9998 | 0.9999 | 0.9999 | 0.9998 |

Note that almost 1/2 of the outage time occurred on 16 November 2003.
* Based on service to all system customers, not just those affected by a particular outage.

Another system-wide outage occurred on 11 February 2004, when a Healy breaker failure interrupted the Intertie. The outage duration for about 75 percent of GVEA's customers was less than 2 hours. Some customers experienced an outage of 4½ hours. It is our understanding that FWA experienced an 8-hour outage.

At EAFB, protective relay settings separate the EAFB electric system from the GVEA electric system whenever transient disturbances occur on the GVEA system. Data provided by GVEA show that this occurred 137 times from January 1999 through October 2003, an average of more than 28 times a year. EAFB does this to protect its system; it has insufficient generation to support the GVEA system. FWA does not have protective relays to separate from the GVEA system under transient conditions. FGA and GMD do not typically have online generation and, therefore, do not need to separate from the GVEA system under transient conditions.

GVEA employs "aggressive" automatic under-frequency relaying to shed load as a means of reestablishing load-generation balance within time con-

straints necessary to avoid system collapse. While this technique causes some service interruptions, it reduces costs and results in lower rates for GVEA customers. Critical facilities such as hospitals, airports, and power stations are never shed. The portion of the system that is shed is rotated so that the burden is shared across the system.

During normal operations, the Railbelt interconnected system bias is 10 MW/0.1 hertz (Hz). When the Intertie trips off, the GVEA bias is 2.5 MW/0.1 Hz.

The Intertie has a combined maintenance plus forced outage rate of less than 2 percent per year. GVEA has a SILOS (shed in lieu of spin) computer-based load shed program that begins at 59.7 Hz and ends at 59.3 Hz. It sheds a variable amount (GVEA's spinning reserve obligation) within 2 seconds. If the frequency continues to drop, GVEA has under-frequency relays (6-cycle action) that begin at 59.0 Hz and end at 58.3 Hz (approximately 30 MW). After this, the Intertie relays open on under-frequency. GVEA then has an additional 23 MW of under-frequency relaying between 58.2 Hz and 58.0 Hz. At winter peak loads, GVEA's current reserve would be 81 MW. Loss of the Intertie would make its reserves 64 MW. If GVEA were to lose a North Pole unit in addition, its reserves would be 0. If GVEA were to lose the entire North Pole Plant, it would only be able to serve 119 MW. In all of the above scenarios, GVEA has 31 MW of interruptible load (Fort Knox Gold Mine) that it would remove prior to curtailing firm load due to lack of capacity.

Load shedding can only reduce the load by 32.5 MW ([60-58.3]/0.1x2.5) before the Intertie opens to Anchorage, then another 23 MW is shed between 58.2 Hz and 58.0 Hz. With the new BESS, GVEA has 27 MW of immediate reserve capacity. GVEA has 31 MW of interruptible load that it would remove prior to curtailing firm load due to a lack of capacity. The BESS combined with load shedding allows GVEA to respond to a power supply loss of about 64 MW without a widespread outage occurring.

EAFB's separation from the GVEA system as described above can be thought of as a load-shedding scheme to ensure EAFB's ability to match its generation to its load. Information provided by GVEA on "separations" or "outages" of its system from each installation are summarized in Table 9.

Table 9. GVEA system separations or outages by installation.

| Installation | Period of Record | | Days | Incidents | Average Days Between Incidents |
|---|---|---|---|---|---|
| | From | To | | | |
| Fort Wainwright | 11-Sep-00 | 13-Sep-03 | 1,097 | 21 | 52 |
| Eielson Air Force Base | 19-Jan-99 | 24-Oct-03 | 1,739 | 136 | 13 |
| Fort Greely | 17-Jul-99 | 23-Oct-03 | 1,559 | 41 | 38 |

The periods of record are for a minimum of 3 years (FWA) up to almost 5 years (EAFB). The data do not include durations of the incidents. It can be seen that EAFB separates from GVEA on average once every 13 days, more often than either FWA or FGA. This is the result of the EAFB protective relay settings described above. EAFB's reconnection to the GVEA system is at EAFB's discretion; the duration of the separation is determined by EAFB.

FWA data on electrical system "trips" over the period 1999 through 2001 indicate 13 "trips" with a total duration of 3 hours and 10 minutes as a result of GVEA system issues and 43 "trips" with a total duration of 25 hours and 58 minutes from FWA system issues. The durations are not directly comparable because of the number of end users affected. However, the information does point out that reliability is not just an issue for the GVEA system. Installation electric systems are also an important element of reliability for an end user.

## GVEA Backup Power Generation

GVEA maintains oil-fired CT generators and diesel engine generators to provide emergency backup generation for its system. These units are located in Fairbanks at the Chena Power Plant and at the Zehnder Power Plant. Total winter backup capacity is approximately 75 MW, and summer capacity is 65 MW. Start-up time for these units is:

- Large CT generators: 15 to 30 minutes from cold start to full load (North Pole)
- Smaller CT generators: 10 to 15 minutes from cold start to full load (Fairbanks plants)
- Stationary diesel engine generators: 8 minutes from cold start to full load

All backup generators are housed in heated buildings.

GVEA has adequate "firm" generation capacity to meet peak load with even the largest generation unit offline. However, the loss of the southern half of the Intertie represents 70 MW of power. Without the Intertie, GVEA must start and run most of its local generation units to meet demand. This occurred as recently as 25 September 1997, when all available Fairbanks generators were needed to meet the loads.

The NPE will increase GVEA's firm resources by 120 MW over the next 5 years. This should provide GVEA with adequate reserve margins to meet almost any contingency without prolonged reliance on its older units. If HCCP is completed, it will add another 50 MW.

## Military Power Sales to GVEA

In 1980, the Alaska Power Swap Act (Public Law 96-571), referred to the "Alaska Federal–Civilian Energy Efficiency Swap Act of 1980," was enacted, the result of very high oil costs in the 1970s and GVEA's interest in being able to buy lower-cost power from the military's coal-fired power plants. GVEA purchased this power until the Railbelt Intertie was completed (Appendix A). With completion of the Intertie, GVEA obtained access to a lower-cost power supply and discontinued its purchases from the military.

The act authorizes any Federal agency to contract for the sale of electric power to a non-Federal entity as long as:

"(a) For the purposes of conserving oil and natural gas and better utilizing coal, any agency is authorized to sell to any non-Federal person, and to enter into contracts for the sale to any non-Federal person of, electric energy generated by coal-fired electric generating facilities of such agency in Alaska without regard to *any provision of law which precludes such sale where such energy is available for other local sources*, [emphasis added] if the agency determines that:

> Such energy is generated by an *existing coal-fired* generating facility;
>
> Such energy is *surplus* to such agency's needs and is in excess of the electric energy specifically generated for consumption by, or necessary to serve the requirements of, any department, agency, or instrumentality of the United States;
>
> The costs to the ultimate consumers of such energy is less than the costs which, in the absence of such sale, would be incurred by such consumers for the purchase of an equivalent amount of energy; and

> Such sale will *result in a reduction in the total consumption of oil or natural gas* by the non-Federal person purchasing such electric energy below that consumption which would occur in the absence of such sale.

(b) Federally generated electric energy sold by an agency as provided in subsection (a) of this section shall be priced to recover the fuel costs and variable operation and maintenance costs of the Federal generating facility concerned which costs are attributable to such sale, plus an amount equal to one-half the difference between:

> the costs of producing the electric energy by coal generation, and
>
> the costs of producing electric energy by the oil of gas generation being displaced.

On the basis of the Alaska Power Swap Act, it appears that provisions within Federal law preclude the sale of Federal energy if such energy is available from local sources. Also, for sales under the Act to occur, the sales must be from an existing Federal coal-fired plant and must result in a reduction in the use of oil or natural gas.

FWA and GVEA signed a contract in 1981. The contract did not include an explicit termination date and is, presumably, still in effect. It is our understanding that EAFB and GVEA signed a similar contract.

Individuals familiar with this contract say that it was not used to any meaningful extent because of the administrative issues associated with such a power sale and then because of the availability of more economical power over the Intertie. As discussed previously, the incremental cost of coal-fired power at FWA and EAFB is relatively high compared to GVEA's base-load resources and other sources in the Anchorage area. During peak periods when the incremental cost is comparable to GVEA's fuel oil–based peaking resources, the installations need generation to be committed to their own loads for peaking and reliability reasons.

Presumably, the term "existing" applies only to those power plants in existence when the Act was passed. A new coal-fired power plant would not qualify. If that is the case, the option of a long-term contract to sell power to GVEA from a new power plant is not available or could require enabling legislation. This may not preclude the ability to do short-term power exchanges between the installations and GVEA without transgressing Federal law. Such arrangements are relatively common in the Lower 48. There must be an economic incentive to do this; this analysis indicates limited opportunities. This issue could be explored further in a subsequent study.

## GVEA Service to FWA, EAFB, FGA, and GMD

GVEA provides electrical service to FWA, FGA, and GMD under Contract DAPC49-020C-007 with the U.S. Army, effective 28 July 2002, for a period of 10 years. GMD paid GVEA's costs to build a 138-kV transmission line tap from GVEA's Jarvis Creek Substation to a new military substation at GMD. EAFB is also served by GVEA, but under a separate arrangement.

Under this contract, each installation makes its purchases under the then-applicable GVEA rate schedule GS-2, General Service, for customers with demands greater than 50 kilowatts (kW). EAFB also makes its purchases under the GS-2 tariff.

### Wheeling from FWA to FGA

Under the contract, the Government may transmit government-generated electric power between DoD installations within Alaska's interior and FGA connection points provided GVEA's transmission facilities can provide such service. The charges for this "wheeling" are:

- Transmission losses at 11.1 percent of power delivered to GVEA for wheeling
- Energy charge at 17.64 percent of the applicable GS-2 energy charge, excluding any cost of power adjustment. This charge shall be applied to the energy delivered to FGA.
- No demand charge

The amount of power delivered to GVEA for wheeling shall not exceed 120 percent of the immediate demand at FGA. At FGA, the estimated maximum demand is 2,000 kW, and the estimated maximum annual consumption is 500,000 kWh.

Based on the current GS-2 (2) rate schedule, the cost to wheel this energy is:

$$(15{,}000 \text{ kWh} * \$0.0667/\text{kWh} + (380{,}000 \text{ kWh} - 15{,}000 \text{ kWh}) * 0.05837/\text{kWh}) * 0.1764 * 1.111 = \$4{,}371.45$$

$$\text{or } \$0.0115 \text{ per kWh}$$

### GVEA Rate Schedule General Service 2 (GS-2)

Rate schedule GS-2 is for those customers with a demand of more than 50 kW. It has three levels of service:

- Medium Commercial, where delivery is taken at utilization voltage
- Large Commercial, where delivery is taken at distribution voltage
- High Voltage Industrial, where delivery is taken at transmission voltage

Table 10 lists the current GVEA GS-2 charges to each facility.

Table 10. GVEA GS-2 charges by facility.

| | FWA | EAFB | FGA | GMD |
|---|---|---|---|---|
| GVEA Rate Schedule GS-2 | (2) Large | (1) Medium | (2) Large | (3) High-Voltage |
| Monthly Charges | | | | |
| Customer Charge | $100.00 | $50.00 | $100.00 | $180.00 |
| Demand Charge ($/kW) | $8.00 | $7.00 | $8.00 | $11.25 |
| Energy Charge ($/kWh) | | | | |
| First 15,000 kWh/month | $0.06667 | $0.08164 | $0.06667 | $0.05197 |
| Over 15,000 kWh/month | $0.05837 | $0.06414 | $0.05837 | $0.05197 |
| GMD Transmission Line Payment | | | | $2,921,264.63 |
| GMD Substation Payment | | | | $1,439,967.20 |

Note that FWA and FGA make purchases under GS-2 (2), which is based on GVEA power deliveries at primary voltage (12.47 kV for FWA and 2.4 kV for FGA). EAFB is under GS-2 (1) with delivery at 7.2 kV. GMD makes its purchases under GS-2 (3), which is based on power deliveries at the 138-kV transmission voltage.

As the voltage level increases, the customer's use of GVEA's transmission and distribution system becomes more limited. GVEA's system investment in step-down transformers, etc., should not be charged to the customer. If a customer takes delivery at transmission or distribution voltage, it should not be paying the allocated costs for the rest of GVEA's system.

The current GS-2 rate design comes from a GVEA study done in 1999. We have reviewed that study, and it did not explicitly recognize this system use issue in its allocation of revenue requirements to customer classes with the GS-2 rate class. This should be corrected in the next cost of service study done by GVEA. This could result in lower charges for GS-2 (2) and (3) service.

As it is, the GS-2 rate design provides very little real cost difference between the three levels of voltage service provided.

Figure 11 shows the cost per kWh for each GS-2 sub-class based on the monthly load factor for the power purchased. It can be seen that at low load factors (very few kWh purchased per kW of demand), the cost per kWh is very high. At a load factor of about 40 percent, the cost per kWh is essentially the same for all three subclasses. High-Voltage Industrial service should pay less than Large Commercial, which in turn should pay less than Medium Commercial. This issue should be addressed by GVEA when it next conducts a cost of service study, which may be as soon as 2004. The installations should become involved in the process to make sure their interests are represented.

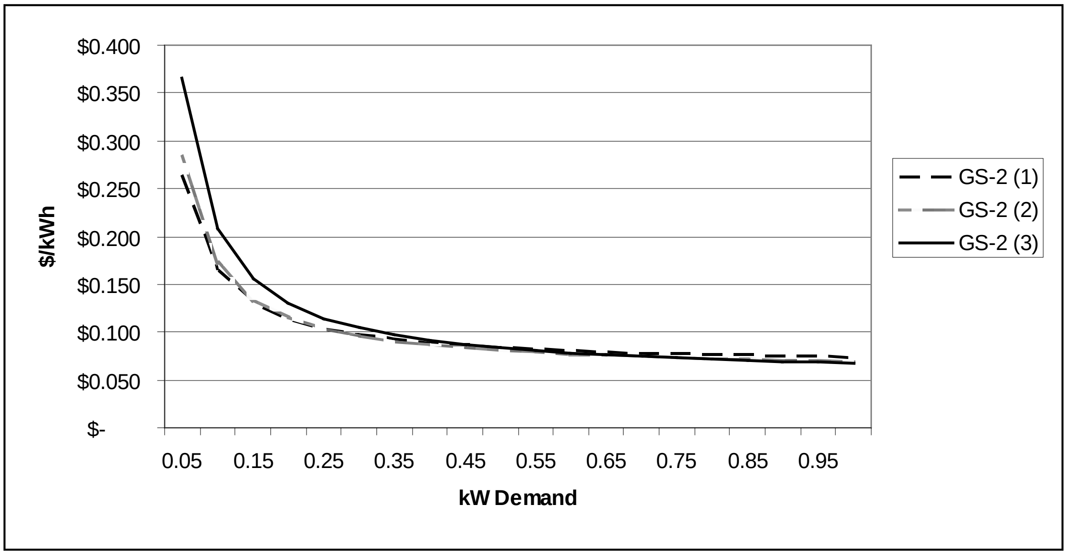



Figure 11. GVEA GS-2 rate schedule.

## Analysis of GVEA Power Bills to Installations

GVEA invoices to each of the installations were obtained and analyzed to determine each installation's loads and power purchase profiles. Note that GVEA revised its rates starting June 2002, so the unit costs shown in the tables reflect the old rates as well as the current rates.

### *FWA*

The GVEA invoices are for GVEA power sales to FWA and not for FWA total electrical consumption.

Table 11 lists GVEA power sales to FWA from January 2002 through August 2003. A review of Table 11 indicates that:

- FWA was late in paying its bills in 4 of the 20 months.

- FWA incurred a power factor penalty of $11,652.20 in January 2003.
- In 11 of the months, FWA incurred a minimum bill charge to meet the minimum bill requirement. The total for these charges was $131,183.76, or almost $0.016 per kWh purchased.
- In 16 of the 20 months, FWA was subject to a demand charge based on 70 percent of the highest demand in the past 12 months (ratchet).
- Over the period, the load factor of power purchases from GVEA was about 7 percent, a very low load factor. This indicates that the purchases from GVEA meet its standby reserve or peaking needs. The GVEA rate schedule is designed to make “peaking” or “standby” purchases from its system very expensive. This can easily be seen in Figure 12 above.
- Over the 20-month period, the cost of all GVEA charges to FWA represented a cost of 20.6 cents per kWh.

This reflects FWA’s lack of backup generator capacity to limit the peaks placed on GVEA.

*EAFB*

Historical GVEA power invoices to EAFB for the 20-month period from January 2002 through August 2003 were obtained and analyzed. Note that the invoices are for GVEA power sales to EAFB and not EAFB total electrical consumption.

Table 12 lists this recapitulation. A review of Table 12 indicates that:

- EAFB was late in paying its bills in 17 of the 20 months.
- In 19 of the 20 months, EAFB was subject to a demand charge based on 70 percent of the highest demand in the past 12 months.
- Over the period, the load factor of power purchases from GVEA was about 66 percent, a high load factor. This indicates that EAFB uses purchases from GVEA to meet its base-load electricity needs and uses its own generation to follow load and meet peaks. The GVEA rate schedule is designed to encourage high load factor purchases.
- Over the 20-month period, the cost of all GVEA charges to EAFB represented a cost of 7.2 cents per kWh.

This indicates EAFB does a good job managing the demand it places on GVEA.

*FGA*

Because of the wheeling arrangement for power from FWA, the FGA power bill is more complicated than for the other three installations.

Table 13 lists the FGA invoice recapitulation. A review of Table 13 indicates that:

- FWA generates slightly more than the 120 percent of FGA load that it is allowed to do under the wheeling agreement. Over the period reviewed, this excess generation was 3.3 percent and had the direct result of increasing FWA's generation costs.
- FGA has a load factor of almost 57 percent for its electrical use, but it purchases power from GVEA at a load factor of about 22 percent, which, as previously discussed, results in high unit costs.
- Over the 20-month period, the cost of all GVEA charges to FGA represented a cost of 9.2 cents per kWh, a moderate unit cost. Note, however, that the cost of an incremental kWh purchase is 5.837 cents per kWh from GVEA.

*GMD*

Because GMD is a relatively new load for GVEA, historical invoices for the period September 2002 through October 2003 (14 months) were analyzed. The invoices represent all of the electricity used by GMD.

Table 14 lists this recapitulation. A review of Table 14 indicates that:

- In 4 of the 14 months, GMD was subject to a demand charge based on 70 percent of the highest demand in the past 12 months.
- Over the period, the load factor of power purchases from GVEA was about 57 percent, a relatively high number. The GVEA rate schedule is designed to encourage high load factor purchases.
- Over the 14-month period, the cost of all GVEA charges to GMD represented a cost of 7.4 cents per kWh.

Fluor, the construction contractor, was responsible for the payment of invoices during the period analyzed.

Table 11. Main Army power plant, Fort Wainwright, cost of purchased power from GVEA, Account No. 0015668-7, GVEA General Service 2.

| Month | kWh | kW | LF | Customer Charge | kWh Charge | kW Charge | Fuel Credit | Min Bill | Late Fee | PF Charge | Reg. Cost Charge | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-02 | 230,400 | 8,568 | 3.6% | $40.00 | $17,763.62 | $53,550.00 | $(4,029.70) | $9,176.08 | | | $82.94 | $76,582.94 |
| Feb-02 | 194,400 | 8,568 | 3.4% | $40.00 | $15,034.82 | $53,550.00 | $(3,400.06) | $11,275.24 | | | $69.98 | $76,569.98 |
| Mar-02 | 206,400 | 8,568 | 3.2% | $40.00 | $15,944.42 | $53,550.00 | $(3,880.32) | $10,845.90 | | | $74.30 | $76,574.30 |
| Apr-02 | 732,000 | 8,568 | 11.9% | $40.00 | $55,784.90 | $53,550.00 | $(13,761.60) | | | | $263.52 | $95,876.82 |
| May-02 | 420,000 | 8,568 | 6.6% | $40.00 | $32,135.30 | $53,550.00 | $(7,896.00) | | | | $151.20 | $77,980.50 |
| Jun-02 | 683,700 | 10,830 | 8.8% | $40.00 | $52,123.76 | $67,687.50 | $(11,718.62) | | $15.00 | | $246.13 | $108,393.77 |
| Jul-02 | 134,400 | 8,568 | 2.1% | $50.00 | $8,865.59 | $59,976.00 | $(1,197.50) | $17,985.91 | $15.00 | | $48.38 | $85,743.38 |
| Aug-02 | 208,800 | 8,568 | 3.3% | $50.00 | $13,627.94 | $59,976.00 | $(1,860.41) | $13,886.47 | | | $75.17 | $85,755.17 |
| Sep-02 | 993,300 | 8,568 | 16.1% | $50.00 | $63,843.78 | $60,900.00 | $(6,655.11) | | | | $357.59 | $118,496.26 |
| Oct-02 | 499,200 | 8,700 | 7.7% | $50.00 | $32,216.44 | $59,976.00 | $(3,344.64) | | $15.00 | | $158.75 | $89,071.55 |
| Nov-02 | 500,400 | 8,568 | 8.1% | $50.00 | $32,293.25 | $62,034.00 | $(3,352.68) | | $15.00 | | $159.13 | $91,198.70 |
| Dec-02 | 196,800 | 8,862 | 3.0% | $50.00 | $12,859.82 | $56,462.70 | $(1,263.46) | $12,551.94 | | | $62.58 | $80,723.58 |
| Jan-03 | 172,800 | 8,066 | 2.9% | $50.00 | $11,323.58 | $46,032.00 | $(1,109.38) | $7,861.60 | | $11,652.20 | $54.95 | $75,864.95 |
| Feb-03 | 64,800 | 8,240 | 1.2% | $50.00 | $4,410.50 | $53,067.00 | $(429.62) | $18,712.12 | | | $20.61 | $75,830.61 |
| Mar-03 | 688,800 | 7,581 | 12.2% | $50.00 | $44,352.74 | $53,067.00 | $(4,566.74) | | | | $219.04 | $93,122.04 |
| Apr-03 | 196,800 | 7,581 | 3.6% | $50.00 | $12,859.82 | $53,067.00 | $(1,304.78) | $11,137.96 | | | $62.58 | $75,872.58 |
| May-03 | 117,600 | 7,581 | 2.1% | $50.00 | $7,790.23 | $53,067.00 | $(818.50) | $15,721.27 | | | $37.40 | $75,847.40 |
| Jun-03 | 357,600 | 7,581 | 6.6% | $50.00 | $23,152.63 | $53,067.00 | $(2,488.90) | $2,029.27 | | | $113.72 | $75,923.72 |
| Jul-03 | 1,092,000 | 6,203 | 23.7% | $50.00 | $70,161.57 | $43,423.80 | $(7,600.32) | | | | $347.26 | $106,382.31 |
| Aug-03 | 722,100 | 6,203 | 15.6% | $50.00 | $46,484.27 | $46,893.00 | $(3,682.71) | | | | $229.63 | $89,974.19 |
| Total | 8,412,300 | | | $940.00 | $573,028.98 | $1,096,446.00 | $(84,361.05) | $131,183.76 | $60.00 | $11,652.20 | $2,834.86 | $1,731,784.75 |
| Avg. kW | 576 | | | | | | | | | | | |
| Avg. Peak | | 8,084 | 7.1% | | | | | | | | | |
| cents/kWh | | | | 0.011 | 6.812 | 13.034 | (1.003) | 1.559 | 0.001 | 0.139 | 0.034 | 20.586 |

Source: GVEA.

Table 12. Eielson Sub Station, Eielson Air Force Base, GVEA General Service 2.

| | kWh | kW | LF | Customer Charge | kWh Charge | kW Charge | Fuel Credit | Min Bill | Late Fee | PF Charge | Reg. Cost Charge | Total | Substation Payment | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-02 | 828,000 | 1,932 | 57.6% | $40.00 | $73,067.30 | $12,075.00 | $(16,790.40) | | $15.00 | | $345.60 | $68,752.50 | $10,500.00 | $79,252.50 |
| Feb-02 | 960,000 | 1,932 | 69.0% | $40.00 | $56,694.50 | $12,075.00 | $(13,987.20) | | $15.00 | | $267.84 | $55,105.14 | $10,500.00 | $65,605.14 |
| Mar-02 | 744,000 | 1,932 | 51.8% | $40.00 | $72,157.70 | $12,075.00 | $(17,822.40) | | $15.00 | | $341.28 | $66,806.58 | $10,500.00 | $77,306.58 |
| Apr-02 | 948,000 | 1,932 | 68.2% | $40.00 | $63,061.70 | $12,075.00 | $(15,566.40) | | $15.00 | | $298.08 | $59,923.38 | $10,500.00 | $70,423.38 |
| May-02 | 828,000 | 1,932 | 57.6% | $40.00 | $55,784.90 | $12,075.00 | $(12,546.48) | | $15.00 | | $263.52 | $55,631.94 | $10,500.00 | $66,131.94 |
| Jun-02 | 732,000 | 1,932 | 50.9% | $50.00 | $60,944.13 | $13,524.00 | $(8,446.68) | | $15.00 | | $341.28 | $66,427.73 | $10,500.00 | $76,927.73 |
| Jul-02 | 948,000 | 1,932 | 73.0% | $50.00 | $53,262.93 | $13,524.00 | $(7,377.48) | | $15.00 | | $298.08 | $59,772.53 | $10,500.00 | $70,272.53 |
| Aug-02 | 828,000 | 1,932 | 57.6% | $50.00 | $64,016.61 | $14,280.00 | $(6,673.20) | | $15.00 | | $358.56 | $72,046.97 | $10,500.00 | $82,546.97 |
| Sep-02 | 996,000 | 2,040 | 67.8% | $50.00 | $50,190.45 | $13,440.00 | $(5,226.00) | | $15.00 | | $248.04 | $58,717.49 | $10,500.00 | $69,217.49 |
| Oct-02 | 780,000 | 1,920 | 54.6% | $50.00 | $57,871.65 | $9,996.00 | $(6,030.00) | | $15.00 | | $286.20 | $62,188.85 | $10,500.00 | $72,688.85 |
| Nov-02 | 900,000 | 1,428 | 87.5% | $50.00 | $50,958.57 | $9,996.00 | $(5,084.64) | | $15.00 | | $251.86 | $56,186.79 | $10,500.00 | $66,686.79 |
| Dec-02 | 792,000 | 1,428 | 74.5% | $50.00 | $50,190.45 | $9,996.00 | $(5,007.60) | | $15.00 | | $248.04 | $55,491.89 | $10,500.00 | $65,991.89 |
| Jan-03 | 780,000 | 1,428 | 73.4% | $50.00 | $48,654.21 | $9,996.00 | $(4,853.52) | | $15.00 | | $240.41 | $54,102.10 | $10,500.00 | $64,602.10 |
| Feb-03 | 756,000 | 1,428 | 71.2% | $50.00 | $45,581.73 | $9,996.00 | $(4,694.04) | | | | $225.14 | $51,158.83 | $10,500.00 | $61,658.83 |
| Mar-03 | 708,000 | 1,428 | 66.6% | $50.00 | $45,581.73 | $11,760.00 | $(4,694.04) | | $15.00 | | $225.14 | $52,937.83 | $10,500.00 | $63,437.83 |
| Apr-03 | 708,000 | 1,680 | 56.6% | $50.00 | $51,726.69 | $9,996.00 | $(5,330.52) | | $15.00 | | $255.67 | $56,712.84 | $10,500.00 | $67,212.84 |
| May-03 | 804,000 | 1,428 | 75.7% | $50.00 | $48,654.21 | $9,996.00 | $(5,261.76) | | $15.00 | | $240.41 | $53,693.86 | $10,500.00 | $64,193.86 |
| Jun-03 | 756,000 | 1,428 | 71.2% | $50.00 | $49,422.33 | $9,996.00 | $(5,345.28) | | | | $244.22 | $54,367.27 | $10,500.00 | $64,867.27 |
| Jul-03 | 768,000 | 1,428 | 72.3% | $50.00 | $56,335.41 | $9,996.00 | $(6,096.96) | | | | $278.57 | $60,563.02 | $10,500.00 | $71,063.02 |
| Aug-03 | 876,000 | 1,428 | 82.5% | $50.00 | $49,422.33 | $9,996.00 | $(3,916.80) | | $15.00 | | $244.42 | $55,810.95 | $10,500.00 | $66,310.95 |
| **Total** | **16,440,000** | | | **$950.00** | **$1,103,579.53** | **$226,863.00** | **$(160,751.40)** | **$-** | **$255.00** | **$-** | **$5,502.36** | **$1,176,398.49** | **$126,000.00** | **$797,931.72** |
| Avg. kW | 1,126 | | | | | | | | | | | | | |
| Avg. Peak | | 1,708 | 65.9% | | | | | | | | | | | |
| cents/ kWh | | | | 0.006 | 6.713 | 1.380 | (0.978) | - | 0.002 | - | 0.033 | 7.156 | | |

Source: GVEA.

TABLE 13. FGA power bills from GVEA.

| | Demand | kWh Total | LF | kWh Read | Purchased kWh | Customer | Demand | Energy | CoP Adj | Reg. Charge | Total | Power Wheeled | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-02 | 1,680 | 938,400 | 76.5% | 638,400 | 373,095 | $40.00 | $10,500.00 | $28,579.88 | $(6,525.43) | $134.31 | $32,728.76 | $7,611.56 | $40,340.32 |
| Feb-02 | 1,656 | 852,000 | 70.5% | 676,800 | 252,724 | $40.00 | $10,350.00 | $19,455.80 | $(4,420.15) | $90.98 | $25,516.63 | $8,065.79 | $33,582.42 |
| Mar-02 | 1,632 | 900,000 | 75.5% | 612,000 | 366,470 | $40.00 | $10,200.00 | $28,077.74 | $(6,889.64) | $131.93 | $31,560.03 | $7,186.69 | $38,746.72 |
| Apr-02 | 1,416 | 758,400 | 73.4% | 681,600 | 170,480 | $40.00 | $8,850.00 | $13,221.71 | $(3,205.03) | $61.37 | $18,968.05 | $7,913.94 | $26,881.99 |
| May-02 | 1,344 | 746,400 | 76.1% | 499,200 | 323,873 | $40.00 | $8,400.00 | $24,848.84 | $(6,088.80) | $116.59 | $27,316.63 | $5,702.46 | $33,019.09 |
| Jun-02 | 1,200 | 624,000 | 71.2% | 436,400 | 275,171 | $40.00 | $7,500.00 | $21,157.23 | $(4,716.42) | $99.06 | $24,094.87 | $4,717.04 | $28,811.91 |
| Jul-02 | 1,224 | 655,200 | 73.3% | 484,800 | 240,031 | $50.00 | $8,568.00 | $15,627.02 | $(2,138.67) | $86.41 | $22,207.76 | $4,734.16 | $26,941.92 |
| Aug-02 | 1,248 | 715,200 | 78.5% | 523,200 | 263,529 | $50.00 | $8,736.00 | $17,131.16 | $(2,348.05) | $94.87 | $23,663.99 | $5,146.31 | $28,810.30 |
| Sep-02 | 1,416 | 746,400 | 72.2% | 468,000 | 335,254 | $50.00 | $9,912.00 | $21,722.23 | $(2,246.20) | $120.69 | $29,558.72 | $4,688.74 | $34,247.46 |
| Oct-02 | 1,632 | 895,200 | 75.1% | 439,200 | 506,334 | $50.00 | $11,424.00 | $32,673.07 | $(3,392.44) | $69.87 | $40,839.50 | $4,437.16 | $45,276.66 |
| Nov-02 | 1,824 | 972,000 | 73.0% | 465,600 | 562,945 | $50.00 | $12,768.00 | $36,296.78 | $(3,771.73) | $77.69 | $45,435.73 | $4,665.12 | $50,100.85 |
| Dec-02 | 1,824 | 1,046,400 | 78.6% | 715,200 | 412,658 | $50.00 | $12,768.00 | $26,676.87 | $(2,649.26) | $56.95 | $36,917.55 | $7,202.15 | $44,119.70 |
| Jan-03 | 2,040 | 1,161,600 | 78.0% | 943,200 | 340,801 | $50.00 | $14,280.00 | $22,077.35 | $(2,187.95) | $47.03 | $34,281.43 | $9,314.27 | $43,595.70 |
| Feb-03 | 1,896 | 866,400 | 62.6% | 859,200 | 144,289 | $50.00 | $13,272.00 | $9,498.61 | $(926.34) | $19.91 | $21,914.18 | $8,199.95 | $30,114.13 |
| Mar-03 | 1,944 | 1,056,000 | 74.4% | 297,600 | 792,043 | $50.00 | $13,608.00 | $50,961.35 | $(5,251.25) | $109.30 | $59,477.41 | $3,026.76 | $62,504.17 |
| Apr-03 | 1,752 | 900,000 | 70.4% | 590,400 | 377,605 | $50.00 | $12,264.00 | $24,433.14 | $(2,503.52) | $52.11 | $34,295.73 | $5,944.88 | $40,240.61 |
| May-03 | 1,560 | 837,600 | 73.6% | 794,400 | 143,932 | $50.00 | $10,920.00 | $9,475.74 | $(954.27) | $19.86 | $19,526.33 | $7,878.79 | $27,405.12 |
| Jun-03 | 1,488 | 768,000 | 70.7% | 679,200 | 204,994 | $50.00 | $10,416.00 | $13,384.29 | $(1,426.76) | $28.29 | $22,451.83 | $6,403.44 | $28,855.27 |
| Jul-03 | 1,488 | 796,800 | 73.4% | 700,800 | 202,162 | $50.00 | $10,416.00 | $13,203.05 | $(1,407.05) | $27.90 | $22,289.90 | $6,760.60 | $29,050.50 |
| Aug-03 | 1,560 | 621,600 | 54.6% | 715,200 | 144,102 | $50.00 | $10,920.00 | $9,486.63 | $(1,002.95) | $19.89 | $19,473.56 | $5,437.93 | $24,911.49 |
| **Total** | | **16,857,600** | | **12,220,400** | **6,432,492** | **$940.00** | **$216,072.00** | **$437,988.46** | **$(64,051.89)** | **$1,465.02** | **$592,518.59** | **$73,959.79** | **$666,478.33** |
| Avg. kW | | 1,155 | | | 441 | | | | | | | | |
| Peak | 2,040 | | 56.6% | | 21.6% | | | | | | | | |
| cents/kWh | | | | | | $0.00015 | $0.03359 | $0.06809 | $(0.00996) | $0.00023 | $0.09211 | | |

Source: GVEA.

## GVEA Rates

Over the past several years, GVEA has made several significant investments in its system, including the Northern Intertie Reinforcement project ($81 million) and the Battery Energy Storage System project ($35 million). Over the next few years, GVEA plans to invest $65 million in the North Pole Expansion project. These investments put upward pressure on GVEA's revenue requirements and rates.

## State of Alaska Energy Plan

The State of Alaska Energy Policy Task Force conducted a study to examine how electricity is generated, transmitted, and distributed in Alaska to meet the state's existing and future electrical needs in a safe and efficient manner. The task force submitted its final findings to the state legislature in December 2003.

Alaska has a limited Railbelt electrical grid with no connection to Canada or to the lower 48 states.

Seven primary utilities serve the Railbelt, as follows:

- Anchorage Municipal Light & Power (AML&P)
- Chugach Electric Association, Inc. (CEA)
- Golden Valley Electric Association
- Homer Electric Association (HEA)
- Matanuska Electric Association (MEA)
- City of Seward
- Aurora Energy.

The generating capacity of the Railbelt electric utilities is about 1,374 MW. Natural gas is the fuel for 67 percent of the electricity generated, coal for 5 percent, hydropower for 15 percent, and fuel oil for the other 13 percent of the energy generated.

Transmission interconnections are mainly the Fairbanks-to-Anchorage transmission line, rated at 345 kV and operating at 138 kV, and the Anchorage to Kenai area transmission line, rated and operating at 115 kV with a transfer capability of 70 MW.

Table 14. GMD—Fluor Power Bills from GVEA, GVEA General Service 2.

| | kWh | kW | LF | Customer Charge | kWh Charge | kW Charge | Fuel Credit | Min Bill | Late Fee | PF Charge | Reg. Cost Charge | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sep-02 | 7,920 | 22 | 50.0% | $100.00 | $528.03 | $176.00 | $(53.06) | | | | $2.85 | $753.82 |
| Oct-02 | 17,520 | 82 | 28.7% | $100.00 | $1,147.14 | $656.00 | $(117.38) | | | | $5.57 | $1,791.33 |
| Nov-02 | 46,800 | 118 | 55.1% | $100.00 | $2,856.22 | $944.00 | $(313.56) | | | | $14.88 | $3,601.54 |
| Dec-02 | 77,760 | 178 | 58.7% | $100.00 | $4,663.35 | $1,424.00 | $(499.22) | | | | $24.73 | $5,712.86 |
| Jan-03 | 101,280 | 178 | 76.5% | $100.00 | $6,036.21 | $1,424.00 | $(650.22) | | $15.00 | | $32.21 | $6,957.20 |
| Feb-03 | 98,160 | 211 | 62.5% | $100.00 | $5,854.40 | $1,688.00 | $(630.19) | | | | $31.21 | $7,043.42 |
| Mar-03 | 84,480 | 214 | 53.1% | $100.00 | $5,055.60 | $1,712.00 | $(560.10) | | | | $26.86 | $6,334.36 |
| Apr-03 | 100,080 | 221 | 60.9% | $100.00 | $5,966.17 | $1,768.00 | $(663.53) | | $15.00 | | $31.83 | $7,217.47 |
| May-03 | 73,920 | 187 | 53.1% | $100.00 | $4,439.21 | $1,497.00 | $(490.09) | | $15.00 | | $23.51 | $5,584.63 |
| Jun-03 | 67,200 | 216 | 41.8% | $100.00 | $4,046.96 | $1,728.00 | $(467.71) | | $15.00 | | $21.37 | $5,443.62 |
| Jul-03 | 50,400 | 172 | 39.4% | $100.00 | $3,066.35 | $1,382.40 | $(350.78) | | $15.00 | | $16.03 | $4,229.00 |
| Aug-03 | 35,760 | 154 | 31.2% | $100.00 | $2,211.81 | $1,237.60 | $(248.89) | | $15.00 | | $11.37 | $3,326.89 |
| Sep-03 | 63,600 | 154 | 55.5% | $100.00 | $3,836.83 | $1,237.60 | $(324.36) | | | | $20.22 | $4,870.29 |
| Oct-03 | 107,520 | 288 | 50.2% | $100.00 | $6,400.44 | $2,304.00 | $(548.35) | | $15.00 | | $42.15 | $8,313.24 |
| Total | 932,400 | 2,395 | | $1,200.00 | $54,433.55 | $18,346.60 | $(5,747.00) | $- | $105.00 | $- | $296.37 | $68,634.52 |
| kW avg. | 106 | | | | | | | | | | | |
| Peak | | 187 | 56.9% | | | | | | | | | |
| cents/ kWh | | | | 0.129 | 5.838 | 1.968 | (0.616) | - | 0.011 | - | 0.032 | 7.361 |
| Source: GVEA. | | | | | | | | | | | | |

This planning effort addressed issues such as:

- Heavy reliance on Cook Inlet natural gas, which is subject to fluctuating oil and gas pricing, to supply power and heat.
- 67 percent of Railbelt electricity generation is fueled by natural gas.
- 80 percent of Anchorage households are heated by natural gas.
- The Railbelt Intertie linking Anchorage, Fairbanks, and the Kenai Peninsula may be at its operating limits. The 70-MW power transfer limitation along a portion of the Intertie reduces the ability to optimize generation dispatch of the Railbelt utilities.
- The mixed ownership of the Railbelt Intertie system. The Alaska Energy Authority (AEA) owns portions of the system, and individual utilities own other portions. This has led to inter-utility disputes over wheeling charges and participation in upgrades.
- Most of the Railbelt's generation capacity is 20-40 years old and will become more costly to maintain or replace. The existing line between Anchorage and the Kenai Peninsula was built in 1962. The existing line between Healy and Fairbanks was built in 1967. Because of transmission constraints that limit power imports from Anchorage, 35 percent of Fairbanks' demand is being supplied from high-cost, local oil-fired generators.
- Cook Inlet gas supplies are tightening. No other source of gas is presently available in the Railbelt.

Selected recommendations from the task force report to the legislature include:

- Structure implementation of a unified Railbelt system operator.
- Support increased vocational trade schools, higher education, and training of technical and professional career staff and management.
- State grants or financing should give priority to unified Railbelt system operation and expanding the grid along the road system (i.e., the "Roadbelt").
- Where common projects are identified as the most cost-effective energy solutions, encourage financial risk-sharing among utilities through a model similar to the Bradley Lake Project agreement.
- Increase the proportion of renewables in long-term fuel sources. Renewables include hydroelectric generation.
- Loop the existing Railbelt energy grid to improve system reliability and serve new markets.
- Advance the physical and cyber security of the critical electrical infrastructure in Alaska.
- Strive to have nationally competitive electrical rates.

Key issues discussed above that directly affect GVEA and, therefore, indirectly the military installations are:

- Reduced Cook Inlet gas supplies that reduce GVEA's ability to import low-cost, natural gas–fired electrical energy to displace its own higher-cost generation.
- Limited reliability associated with a transmission line to the Anchorage area.
- Aging generation infrastructure and limitations on the ability to permit replacement generation.
- The possibility of a pipeline for North Slope natural gas.

Related to the State Energy Plan work, five of the Railbelt utilities cooperatively sponsored a Railbelt Energy Study* that addressed electric generation fuel supply and pricing, generation unit retirements, reliability, and generation and transmission investments for the Railbelt utilities. The base case analysis indicated that an 85-MW combined-cycle plant should be built in the Fairbanks area by 2008 and that 60- or 130-MW combined-cycle plants would be built in the Fairbanks and Anchorage areas around 2012 depending on load growth in each area. The study looked at the implications of using coal assuming that it could be delivered to the Anchorage and Fairbanks areas at the same price paid by GVEA at its Healy plant. The analysis found that a 150-MW coal plant built in either Anchorage or Fairbanks in 2015 would produce significant savings compared to the base case and would provide a significant reduction in the strategy risk level.

There is also an issue regarding the future of the Healy Clean Coal Project owned by the AEA. It is our understanding that GVEA and the state are working toward an agreement to complete the HCCP as a more conventional coal plant. The HCCP is relatively close to Denali National Park (a Class I air shed), and emissions are expected to be a significant issue. This is also true for the UCM-proposed Emma Creek 200-MW coal-fired plant in the Healy area.

* Ater Wynne LLP, and R.W. Beck, *Railbelt Energy Study, Final Report* (15 January 2004).

# 5 Strategic Energy Forum

CH2M HILL hosted a Strategic Energy Forum in Fairbanks, AK, on 18–19 November 2003, as part of the ongoing effort of the Joint Long-Range Energy Study for the Greater Fairbanks Military Complex. The objective of the forum was to provide the study effort with information from leading technology experts, energy suppliers, and distributors regarding technology solutions for the next 25+ years.

The goals of the forum were to:

- meet with the leading technology experts, energy suppliers, and distributors in the region
- receive formal presentations on various technology solutions
- conduct group discussions on these technology solutions
- refine/obtain estimated capital costs, operations and maintenance costs, emissions, reliability, etc., for each technology
- publish "proceedings" from the forum.

The forum was separated into the following categories:

- Installation Energy Challenges and Plans
- Energy Supplies in the Railbelt and Greater Fairbanks Areas
- Technologies
  Mature
  Emerging
- Industry Perspective (Energy Infrastructure)
- Regulatory Concerns
- Environmental Concerns
- Group Discussions and Open Forum.

Presentations were made by:

- Fort Wainwright
- Eielson Air Force Base
- Fort Greely
- Missile Defense Agency
- Science Applications International Corporation (SAIC) on Cook Inlet natural gas supplies
- Golden Valley Electric Association on power supply and transmission
- Usibelli Coal Mine on coal supplies

- Alaska Department of Natural Resources on potential natural gas supplies in Alaska
- Fairbanks Natural Gas on LNG and natural gas distribution in Fairbanks
- CH2M HILL on conventional coal technologies
- Gas Technology Institute on combined heat and power
- National Energy Technology Lab on advanced coal-burning technologies
- Solena Energy Group on plasma gasification and vitrification
- University of Alaska–Fairbanks on renewable energy resources for Alaska
- U.S. Army Cold Regions Research & Engineering Laboratory on district heating and geothermal heat pumps
- NC Power Systems on standby generation and emergency power systems
- Regulatory Commission of Alaska
- Alaska Department of Environmental Conservation
- U.S. Army Engineer Research and Development Center, Construction Engineering Research Laboratory.

After presentations in each category, the participants were divided into teams and given specific questions relative to the category speakers and the overall project goals. Each team was asked to report back to the overall group with its responses. This dialogue helped with group dynamics and participant interaction, and assisted the project delivery teams in identifying new technology solutions.

The forum agenda is listed in Table 15. Forum proceedings have been published separately.

Table 15. Joint Long Range Energy Study for "Greater Fairbanks Military Complex" Strategic Energy Forum, Fairbanks Princess Riverside Lodge, Fairbanks, AK, 18–19 Nov03, Agenda

| Date & Time | | Date and Speaker | Speaker | Organization |
|---|---|---|---|---|
| Tuesday, 18 Nov | | | | |
| 8:00–8:10 | Am | Welcome and Introduction | Frank Abegg | CH2M HILL Team |
| 8:10–8:30 | Am | Overview of Greater Fairbanks Military Complex Study | John Vavrin | Army Construction Engineering Research Lab (CERL) |
| | | Panel Discussion: Installation Energy Challenges/Plans | | |
| 8:30–9:45 | Am | Fort Wainwright | Pat Driscoll | Fort Wainwright |
| | | Eielson AFB | Mike Lee | Eielson AFB |

| Date & Time | | Date and Speaker | Speaker | Organization |
|---|---|---|---|---|
| | | Fort Greely | Larry Ryan | Fort Greely |
| | | MDA | Don Henley | Missile Defense Agency |
| | | Discussion/Q&A | All Panelists | |
| 9:45–10:00 | am | Break | | |
| 10:00–11:20 | am | Panel: Railbelt and Greater Fairbanks Energy Supplies | | |
| | | Railbelt Energy Resources and Outlook | Charles Thomas | SAIC |
| | am | Fairbanks Electric Energy Issues and Outlook with Focus on Fairbanks | Kate Lamal | Golden Valley Electric Association |
| | am | Q&A | All Panelists | |
| 11:20–12:00 | am | Group Discussions & Report Back | Audience | |
| 12:00-1:25 | pm | Lunch | Hosted (Adjoining Room) | |
| 1:25–1:50 | pm | Coal Resources and Long Term Availability | Steve Denton | Usibelli Coal |
| 1:50–3:05 | pm | Panel: Natural Gas and Oil Resource Availability | | |
| | | Alaska Gas & Oil Pipeline Possibilities | Steve Porter | Alaska Dept. of Revenue |
| | | Natural Gas Possibilities for Greater Fairbanks | Mark Myer | Alaska Dept. of Natural Resources |
| | | Existing Gas Supply & On-Installation Distribution Possibilities | Dan Britton | Fairbanks Natural Gas |
| | | Q&A | All Panelists | |
| 3:05–3:20 | pm | Break | | |
| | | Panel: CHPP Technology | | |
| 3:20–4:25 | pm | New and Proposed Coal CHPP Technologies | Tony Taladay | CH2M HILL |
| | | New and Proposed Gas/Oil Technologies | Tod O'Connor | Gas Technology Institute (GTI) |
| | | Q&A | Panelists | |
| 4:25 -5:00 | pm | Group Discussions and Report Back | | |
| | | | | |
| Wednesday, 19 No | | | | |
| 8:00–8:05 | am | Welcome Back | Frank Abegg | CH2M HILL Team |
| 8:05–9:35 | am | Panel: Emerging Energy Technology | | |
| | | Pressurized Fluidized Bed and Other DOE Sponsored Technology | Don Bonk | National Energy Technology Lab |
| | | Plasma Technology | Curt Bagnall for Dennis Miller | Solena Group |
| | | Fuel Cells, Wind, Solar, and Geo- | Dennis Witmer | University of Alaska at |

| Date & Time | | Date and Speaker | Speaker | Organization |
|---|---|---|---|---|
| | | thermal in the Arctic Environment | | Fairbanks |
| | | Q&A | All Panelists | |
| 9:35–10:00 | am | Long-Range Transmission of Heat/Geothermal Heat Pumps | Gary Phetteplace | Army Cold Regions Research & Engineering Lab (CRREL) |
| 10:00–10:15 | am | Break | | |
| 10:15–11:25 | am | Panel: Industry Perspectives | | |
| | | GVEA Perspective/Suggested Solutions | Mike Wright | Golden Valley Electric Association |
| | | Aurora Energy Perspective/Suggested Solutions | Buki Wright | Aurora Energy |
| | | Open Mike/Q&A | Panelists/Attendees | |
| 11:25–12:00 | am | Group Discussions & Report Back | Audience | |
| 12:00–1:30 | pm | Lunch | Hosted (Adjoining Room) | |
| 1:30–1:55 | pm | On-Installation Emergency/Back-up Generation | Gary Hirschberg and Jamie Foresman | NC Power Systems/Caterpillar |
| 1:55–2:20 | pm | Regulatory Opportunities and Constraints | Brad Perrson | Regulatory Commission of Alaska |
| 2:20–2:40 | pm | Break | | |
| 2:40–3:45 | pm | Panel: Environmental Considerations | | |
| | | Air Permitting Issues/Requirements | John Kuterbach | Alaska Dept. of Environmental Conservation |
| | | Groundwater/Wastewater Issues/Requirements | Luke Boles | Alaska Dept. of Environmental Conservation |
| | | Q&A | All Panelists | |
| 3:45–4:20 | pm | Group Discussions and Report Back | Audience | |
| 4:20–4:45 | pm | Open Forum | All Participants | |
| 4:45–5:00 | pm | Forum Insights for Greater Fairbanks Military Complex Study | Curt Bagnall | CH2M HILL Team |
| 5:00 | pm | Adjourn | Frank Abegg | CH2M HILL Team |

# 6 Ownership Options

The military owns the heating and electrical systems at all of the GFMC installations. GMD facilities are owned by the Space Missile Defense Command, but operation is provided as part of The Boeing Company's contract operations of the GMD facilities.

The Air Force has made a determination that it will continue to own and operate all EAFB heating and electrical system facilities because of unique security conditions at EAFB. Ownership options for heating and electrical systems at the other GFMC installations include continued Government ownership and privatization. An option under continued Government ownership is for the Government to lease the facilities to a third party. This would be similar to privatization except for the fact that actual ownership of the facilities would continue to reside with the Government.

The feasibility of privatization and the feasibility of leasing as an option with continued Government ownership are evaluated below.

## Feasibility of Heating and Power System Privatization

This evaluation is limited to identification of any reasons or conditions that would necessarily preclude utility privatization at the installations included in the GFMC. Detailed evaluation of utility privatization feasibility is the subject of separate, on-going analyses by the Department of Defense (DoD).

For the purposes of this study, "utility privatization" refers to the sale of the utility system to a separate entity with the DoD purchasing utility service from the new owner or simply entering into a utility service contract with a separate entity rather than building and operating new utility service properties. Accordingly, it would be possible for the military to continue to own existing utility systems while privatizing service to meet loads not met by those systems. Outsourcing a utility systems operation while DoD continues to own it is generally not included in DoD's definition of utility privatization.

Among privatization factors evaluated are:

- Conformance with enabling legislation and DoD directives for privatization of military utility systems
- Physical characteristics of existing heating and electric utility systems within the GFMC
- Consistency with State of Alaska laws and regulations
- Market interest in acquiring a contract to provide heating and electric utility services at the GFMC installations.
- Evaluation of each of these factors is provided below followed by a recommendation on the utility privatization within the GFMC.

### Evaluation Factors

*Conformance with Enabling Legislation and Department of Defense Directives*

Background to legislation and DoD directives that support utility privatization are presented below followed by an evaluation of GFMC installation conformance to the requirements of those documents.

Background

Congressional legislation and DoD directives authorize and direct the Army, Navy, and Air Force to privatize utility systems where such privatization can be accomplished within specific economic criteria and without creating an undue security risk to the United States.

In the 1990s, DoD concluded that privatization of its utility systems was a way to accomplish three objectives: (1) to infuse private sector capital to modernize the utility infrastructure, (2) to lower costs as a result of greater efficiency, and (3) to enable the military services to focus on core responsibilities. However, the process to accomplish this goal was slow. One reason was that DoD was required to obtain special approval from Congress for each system sale. To speed the process and capture the benefits of privatization, DoD proposed legislation for broad-based authority to privatize its systems more expeditiously.

In response, Congress passed legislation, as part of the Defense Authorization Act of 1998, giving the DoD authority to convey utility systems to private ownership. The legislation is included in the United States Code as Title 10, Section 2688, Utility System Conveyance Authority (10 USC 2688). The statute allows the DoD to privatize its utility systems under the following important conditions:

- Each utility is privatized through full and open competition if more than one entity has interest in the privatization
- Utility systems are sold for fair market value
- Each privatization has lower costs and is economically beneficial to the United States
- Twenty-one days prior to conveyance of any utility system, Congress is notified and provided analysis demonstrating that the privatization is economically beneficial to the United States. (This allows Congress to take action to cancel or delay conveyance if it so chooses.)

In December 1998, the DoD issued Defense Reform Initiative Directive (DRID) 49. It directed the Army, Navy, and Air Force to privatize every government-owned electric, water, wastewater, and natural gas utility system unless security concerns required that DoD retain ownership or privatization was uneconomical.

As DoD worked to implement utility privatization, numerous policy and analytical issues arose. As a result, DoD issued new guidance through a memorandum from the Deputy Secretary of Defense on 9 October 2002.

The guidance supercedes DRID 49 and constitutes DoD policy and regulations that are in effect today. As the memorandum states, it "provides improved guidance for conducting economic analysis, protecting the government's interests and making a determination to privatize and conforming with state laws and regulations."

Among the important features of the guidance are:

- *Exclusion for Unacceptable Risk*. The guidance reaffirms that privatization will not occur where it would create unacceptable risk to the base mission or compromise classified operations or property.
- *Exclusion for Lack of Interest*. The guidance exempts utility systems from privatization if no market interest is demonstrated for the utility system.
- *No Franchise Rights*. Within the United States, DoD bases are almost always located within the franchise or service area granted by the state to one or more utilities. Usually the franchise or service area is exclusive to a single utility. However, the guidance incorporates a legal opinion from the DoD Office of the General Council that utility service "on-base" is not subject to state regulation since the DoD retains sovereign immunity for utility systems under 10 USC 2688. A noted excep-

tion in the General Council's opinion is that purchase or acquisition of electric commodities is dependent on state law.

- *Economic Analysis from United States Perspective*. DRID 49 required that the economic analysis be conducted from the DoD's perspective. This meant that Federal income taxes recovered through charges for utility service counted as a privatization cost in the comparison of privatization costs with costs of continued DoD ownership. Consistent with 10 USC 2688, the guidance changes requirements for economic analysis to be conducted from the United States perspective. This recognizes that Federal income tax is a revenue to the Internal Revenue Service. Therefore, recovery of Federal income taxes through charges to the DoD is offset by payments to the IRS. The guidance specifically requires that Federal income tax payments therefore be adjusted out of proposed charges for the purpose of cost comparison with continued DoD utility ownership.
- *Inclusion of "Should Costs."* In estimating the cost of continued DoD utility ownership for its economic analysis, the DoD must base its estimates on the costs that it would incur if it maintained utility systems at industry standards. This cost is referred to in the guidance as the DoD's "should costs" and makes the cost comparison fair.
- *Allowability of Interest Charges*. Normally, the FARs do not allow contractors to charge the Government for their full interest costs; they are allowed to only recover an established "Facilities Capital Cost of Money" equal to the Government's cost of capital. However, because this would significantly reduce interest in privatizing DoD utility systems, and therefore competition, the guidance essentially waives these FAR requirements. Within certain requirements, the guidance allows utility privatizers to recover interest when its charges are based on amortization of capital upgrade and renewals costs. This allowance was originally granted in a letter from the Office of the Under Secretary of Defense on 15 April 2002, which is incorporated into the guidance.

### Evaluation

It is clear from the DoD directives and guidance that DoD seeks to privatize utility systems wherever possible. Numerous provisions in the OSD guidance were made to accommodate privatization. (e.g., economic analysis from the United States perspective, inclusion of "should costs," and allowability of interest charges). As long as privatization of a utility system is economical and does not create an undue security risk, the DoD has mandated that privatization occur.

GFMC heating and electrical systems comply with the specified requirements for privatization with one exception. The Air Force has concluded that EAFB is exempt from utility privatization because of unique security conditions at the base. Therefore privatization of the heating and electrical systems at EAFB is infeasible.

However, there is no apparent conflict with legislative requirements or DoD directives at FWA and FGA. While actual privatization bids must be obtained to know for sure, there is no basis to believe that privatization of the heating and electrical systems at the two bases would be uneconomical.

*Physical Characteristics of GFMC Heating and Electric Utility*

While portions of the GFMC heating and electrical systems are old, only the utilidors may create significant privatization problems. Liability issues surrounding ownership and continued use of those corridors may be difficult to negotiate. However, such negotiations are possible if both the DoD and selected bidder are willing to share risk equitably

Another possible issue could be that design standards for plant and equipment at the installations differ from those of the local utility. However, this issue is likely to be managed in one of a number of ways. First, in places where plant and equipment are in violation of state or Federal regulations, changes would be required in DoD estimates of "should costs." Accordingly, the cost of such changes would be included in calculation of both the status quo and privatization costs. Second, the local utility may choose to make other changes in plant and equipment to conform to its standards over time rather than immediately. This would substantially mitigate potential added cost of such changes. Third, even if the local utility requires changes to existing installation plant and equipment, others may not. Private entities may well be willing to own and operate all or most of the existing heating and electrical systems at the installations.

*Consistency with State of Alaska Laws and Regulations*

As mentioned above, OSD is of the opinion that utility privatization at military bases is not subject to state regulation. However, the exception of electricity from this opinion is an important distinction. OSD believes that states have authority to regulate electric supplies generated on military in-

stallations.* In addition, some states may believe that they have the authority to regulate all utility services by entities that privatize utility systems at military installations.

As noted in “Alaska Utility Regulatory Considerations” (p 22), it does not appear that regulation by the Regulatory Commission of Alaska will be an obstacle to privatization of military utility systems in Alaska. Generally the RCA’s regulatory charter is in protecting the public interest. Accordingly, the RCA would not likely attempt to regulate privatization of on-installation heating and electric energy utility systems as long as they are kept separate from other systems that serve the general public. The RCA would likely seek to regulate privatized heating or electric utility systems if their accounts were commingled with those of systems serving the general public. Even under those conditions, there should not be any regulatory barriers to privatization of utility systems at the GFMC installations.

*Market Interest in Heating and Electric Utility Services at the GFMC Installations*

There appears to be adequate interest among competent utility service entities to privatize the utility systems at the GFMC installations. At the Strategic Energy Forum held as part of this study in November, 2003, a number of private entities expressed interest in privatizing heating and electric utility systems within the GFMC. Interest was expressed in providing heating and electric utility service for individual installations as well as for combinations of installations. Specifically, interest was expressed by GVEA, AE, FNG, and Tikigaq Energy and Utility Infrastructure Group. In addition, Andex Resources, expressed interest in selling natural gas supplies to the GFMC installations. Additional market interest in providing heating and electric utility service to the GFMC installations would likely result from a request for statements of interest.

### Recommendations

The heating and electric utility systems at EAFB are exempted from privatization due to security concerns. However, there are no barriers to privatization of the heating and electric utility systems at FWA and FGA. Privatization of utility systems at those installations is possible for the following reasons:

* As with all utility commodities, states have authority to regulate electric energy supplies delivered to military installations from off-installation sources.

- Privatization action at the installations can comply with requirements of enabling legislation and DoD directives.
- Physical characteristics of the existing utility systems are manageable.
- Privatization can be accomplished under Alaska law and regulation.
- There is demonstrated interest in the GMFC systems by private firms capable of successfully owning and operating the systems.

Some interested parties have expressed concerns about the ability of the private sector to perform adequately and reliably in meeting critical energy needs of the GFMC. While these concerns are common to utility privatization efforts at all military installations, they are real and important especially given the extreme weather conditions in the Fairbanks area. To address these concerns, utility service providers must be prudently selected and contracts carefully negotiated to provide assurance that services will meet reliability, security, and quality requirements that are critical to each installations mission.

At the same time, privatization is a possible vehicle for improving reliability and lowering costs of heating and electric utility service at the installations. Privatization could have an impact of more fully integrating installation systems with regional heating and electric utility supplies.

Accordingly, a recommendation of this study is for the Army to continue with its process to seek bids to privatize the heating and utility systems at FWA and FGA.

## Feasibility of Leasing Heating and Power Systems

Leasing of GFMC heating and electrical systems to a third party is possible, but not likely to be feasible. At EAFB, the heating and electrical systems are exempt from privatization because of unique security reasons. It is therefore likely that these security concerns would also exclude leasing the systems as an option. At FWA and FGA, Army policy is to privatize the heating and electrical systems. Therefore, leasing of those facilities would only be an option if privatization proves to be infeasible.

### General Advantages and Disadvantages

Leasing GFMC heating and electrical facilities would have advantages and disadvantages. Among the advantages would be that:

- The installations would retain long-term control and ownership of the facilities.

- The installations could cancel the leasing contracts if contractor performance was not acceptable. This would allow the installations to take over control if necessary.
- It is possible for existing or new facilities to be used to serve more than just the installations' needs by providing heating or power service to other users. This could improve overall system efficiency and lower the cost of service to both the installations and to other users. Such an arrangement is called an "enhanced use lease."
- Private entities that lease the facilities may be able to obtain Federal income tax benefits from the lease.

Disadvantages include that:

- The installations continue to ultimately be responsible for the heating and electrical systems. In particular, the installations continue to be responsible for system improvements and expansions.
- Private entities are subject to Federal income tax possibly including tax on the system value as a "contribution in aid of construction" at the start of the lease. The private entity's added tax burden would be passed on to the government as part of the fee for heating and electrical service provided to the installations.

### Enhanced Use Leasing

One approach to improving heating and electrical systems at FWA, FGA, and the surrounding communities might be enhanced use leasing of facilities. As noted above, if leasing to a third party would allow the facilities to be used more efficiently by providing value to other customers, the cost of service to the installations could be lowered. Enhanced use leasing of existing and new heating and electric generation facilities at FWA and FGA are discussed below.

#### *Existing Facilities*

There do not appear to be any existing heating or electric generation facilities that are candidates for enhanced use leasing. Either any reserve boiler capacity is needed for reliability reasons (FWA) or there is very little nearby load that might be a market for the heat (FGA). Excess heating capacity in the spring through fall has no market.

Similarly, FWA does not have excess power generation capacity for sale during the peak, winter season. The military, as a matter of policy and

perhaps state law, is unable to sell electricity at the retail level. GVEA is the only market at the wholesale level.

*New Facilities*

Enhanced use leasing is a theoretically viable ownership option at FWA and FGA. CHPPs could be sized to meet the combined needs for additional heating and power at FWA and the surrounding community or FGA and the surrounding community. Further, it could be designed to optimally meet the heating and power requirements. For example, if needed to meet market demands, CHPP facilities could be designed based on power requirements with steam as its by-product. Further, it could be designed at larger size than it would if it were to simply meet installation requirements; this might provide added efficiencies from economies of scale.

However, privatization is a more likely ownership option for new facilities sized to provide efficiencies to both the Army and the surrounding communities. The primary reason for this is the Army's policy preference for privatization. This is consistent with the philosophy that public utilities and other private entities are more appropriate owners of facilities built to meet public needs; the Federal government should not build facilities to compete in heating and power markets.

**Recommendation**

Leasing, particularly enhanced use leasing of new facilities, is not a likely ownership option for heating and electric systems within the GFMC. It is not a likely option for heating and electric systems at EAFB because of the unique security considerations that have exempted those systems from privatization. At FWA and FGA, privatization is the Army's preferred ownership option over leasing. While enhanced use leasing could be a successful tool for obtaining efficiencies for new regional heating and power generation, it is by policy a secondary option to privatization. Therefore, privatization of the heating and electrical systems at FWA and FGA, rather than leasing, should be pursued as the primary ownership alternative to continued Government ownership and operation.

# 7 Installation Heat and Power System Descriptions

## FWA Heat and Power Systems

### Central Heat and Power Plant

Over the past several years, the Army has invested $65 million to repair the FWA CHPP, build a new baghouse to bring the plant into compliance with the Clean Air Act, and upgrade the turbines' cooling system. The Post has also begun a long-term program to renovate its utilidor system. There are plans to complete the boiler plant refurbishment ($18 million) and to add an air-cooled condenser to the CHPP ($29 million). This work is expected to be completed by the end of fiscal year 2005.

*Boiler and Steam System*

The CHPP configuration is the result of a major plant extension that took place in the early 1950s. The original plant had two 75,000-lb/hr boilers and two STGs. These original boilers have been abandoned in place. The current plant consists of six 150,000-lb/hr, 425-psig, 660 °F coal-fired spreader-stoker boilers providing steam to four controlled-extraction steam turbines (Figure 12). The rated output of turbines 1, 3, 4, and 5 is 5 MW. Turbine 2 has been abandoned in place. The total rated plant output is 20 MW.

Each boiler discharges steam into a 400-pounds-per-square-inch (psi) ring header, from which steam is supplied to individual turbines. Turbine 1 is a back-pressure turbine that supplies 10-psig steam to the deaerators and other plant uses. Because of reductions in the limited need for 10-psig steam, Turbine 1 does not run smoothly until outdoor temperatures are well below 0 °F, and its output is rarely over 3 MW. Turbines 3 through 5 are condensing turbines that discharge into water-cooled condensers at 1.5" mercury (Hg) pressure. Two of these three turbines were rebuilt within the past 3 years. Currently, condenser cooling water is provided from a cooling pond that is located southwest of the plant.

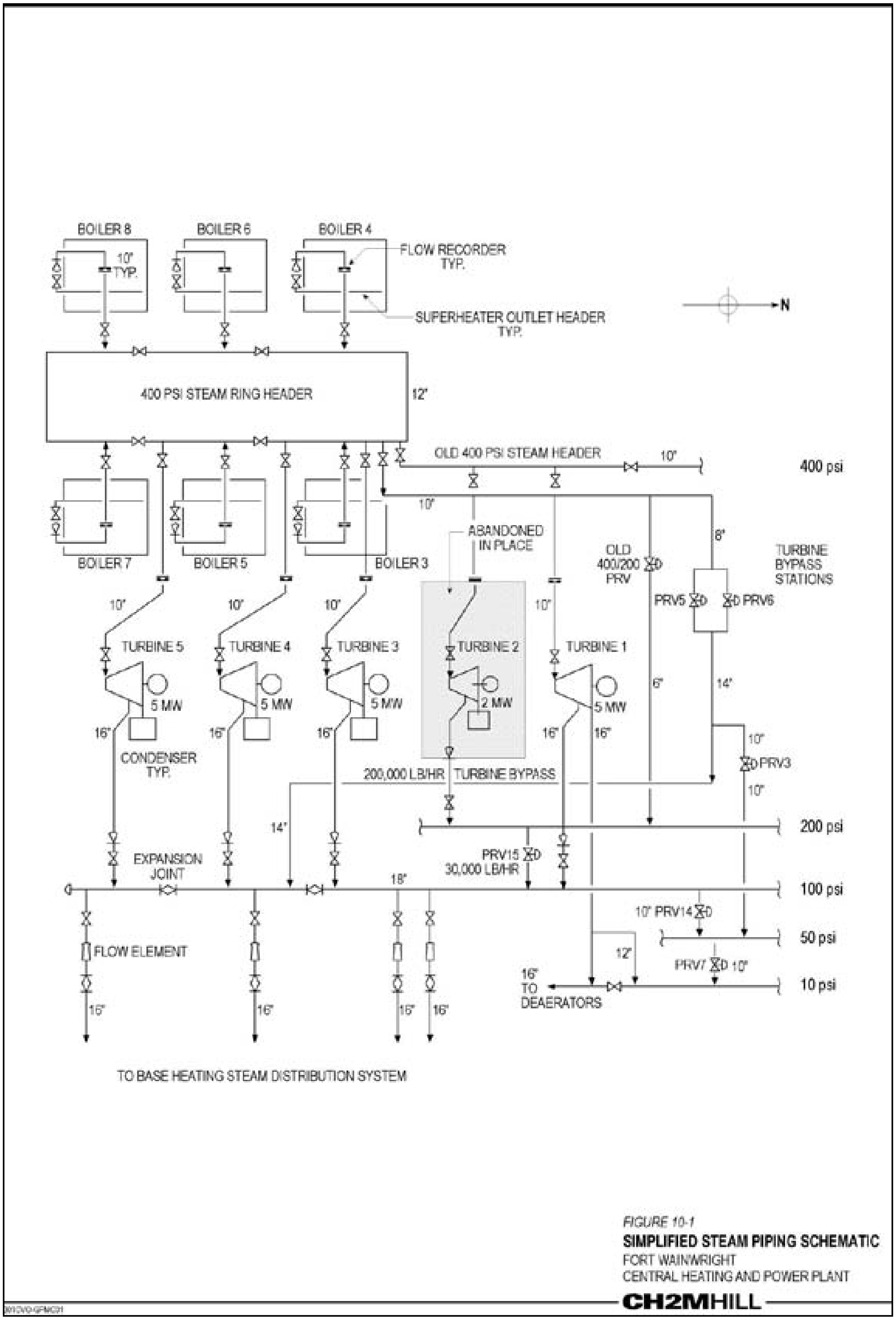



Figure 12. FWA boiler and steam system.

Steam is extracted from the turbines at 100 psig to provide heat for the installation. The extraction steam is discharged into a header, which supplies the Post's steam distribution system. The distribution system consists of a network of looped and valved steam supply and condensate return piping located in a utilidor system. Looped and valved piping allows for isolation of problem areas and back-feeding steam from alternate directions. The utilidor system also includes water distribution and sewer lines; the heat from the steam piping provides freeze protection for these lines.

Boiler output is varied as needed to meet both FWA heating steam and FWA and FGA electric power demand. In the winter when the demand for heating steam and electric power is high, three boilers are typically required, with about 60 percent of the steam going to the steam turbines and extracted at the 100-psig extraction point. The remainder is passed to the condenser. In the summer when the demand for heating steam is low, two boilers operate, with 30 percent of the steam extracted at the 100-psig extraction point and 70 percent of the steam continuing through the turbines to the condenser to produce additional electric power.

A steam bypass with pressure-reducing stations is provided between the 400-psig boiler ring header and the 100-psig extraction steam header to provide about 200,000 lb/hr heating steam to the Post in case of steam turbine unavailability.

Condensate from the Post and plant heating systems is returned to a condensate return tank at the plant and pumped to two deaerators. From the deaerator, feedwater is pumped to a ring header from which branch lines supply water to each boiler economizer inlet.

Make-up water is provided from the potable water system, wells, or the cooling pond and treated in a 350 gallons-per-minute (gpm) capacity, reverse osmosis, filtration water-treatment system.

Each of the six boilers is served by forced-draft (FD) and induced-draft (ID) fans. Each FD fan takes suction from a vertical duct that supplies combustion air to the fan from the top of the boiler room. Indoor air is mixed with outdoor air. Outdoor air is preheated in steam-heated glycol-filled coils. There are no air heaters exchanging heat between the combustion air and the flue gas.

A single ID fan preceded by a multiclone dust collector evacuates flue gas from each boiler. Each ID fan discharges into an insulated metal stack located on top of the boiler room. The stack is about flush with the highest building structure (the coal conveyor enclosure on top of the boiler room). The elevation of the top of each stack is about 85 ft above grade. During 2004, all six boiler stacks will be modified and connected one at a time to the new baghouses.

*Coal Delivery and Handling*

Coal is delivered to the plant by rail from the UCM and stored in a 180-day capacity active coal pile located on the south side of the plant. Railroad cars are unloaded via a car shaker. Coal from the railcars is dumped into a hopper below by opening the cars' bottom gates. The coal is conveyed through a crusher to an elevator. A conveyor on top of the elevator delivers coal to the boiler storage bunkers. This conveyor is reversible so that coal can be delivered either to the storage bunkers or through a chute to the foot of the coal pile on the opposite side of the elevator. Coal from the coal pile is supplied to the boilers via a reclaim hopper from which coal is conveyed to the bottom of the coal elevator.

The original coal-handling system on the north side of the building is used as a backup. The system consists of a reclaim hopper, an elevator, and a conveyor to the boiler bunkers. Coal from the coal pile is delivered to the north reclaim hopper by a bucket loader.

Ash is removed from the boiler hoppers by a pneumatic vacuum system. There are two independent but interconnected systems, each serving three boilers. Heavier ash is separated in a cyclone separator on top of the ash silo. Lighter ash leaving the cyclone separator is collected in a baghouse located upstream of a rotary blower. From the silo, ash is trucked to the Post landfill. There is adequate capacity at the landfill to continue to receive ash well into the future.

### Repair Projects

*CHPP*

The CHPP is being repaired. To date about $45 million has been spent. Another $17.8 million is being requested to complete the repair work. By that point, the known deficiencies at the CHPP will have been corrected

and the plant returned to current Occupational Safety and Health Administration (OSHA) and EPA emissions standards.

The repair work includes the boilers, coal- and ash-handling systems, and other support systems, with the exception of the turbines and the main electrical systems. Repairs and renovation include:

- boilers
- coal and automated ash-handling systems
- continuous and intermittent blow-down systems
- steam (400 psi, 100 psi, and 10 psi) lines
- boiler feed water
- condensate handling and treatment systems
- makeup water
- auxiliary cooling water
- auxiliary electric.

The project also addresses the need to bring the interior coal and ash dust–handling systems into compliance with OSHA requirements by enclosing the conveyors and installing a vacuum collection system to remove coal dust.

At the completion of this effort, the CHPP will be returned to a serviceable level of repair. The past history of breakdown maintenance will be largely overcome. A study completed in 1996 stated that at that time maintenance was performed only when equipment broke down. There was no preventive maintenance program. As a result, it should be expected that even with all of the repair work being done, there may be existing unknown problems that will manifest themselves at some future date.

*Emission Control Project (Baghouse)*

A new emission control system, commonly referred to as “the baghouse,” will bring the power plant into compliance with the Federal Clean Air Act. (EPA filed a formal complaint on 30 December 1999, for power plant violations under the Clean Air Act.) The baghouse project includes six new full-stream bag houses, one for each boiler, in a new building adjacent to the present power plant. Boiler exhausts will flow through the bags and filter particulates from the air before exhaust gases are released into the atmosphere. Each baghouse includes five modules containing 220 bags each. When the work is completed in 2004, the boiler exhaust particulate levels and visual opacity level will meet the plant’s operating permit emission requirements. The project cost is $22 million.

*Air-Cooled Condenser Upgrade*

The turbine cooling system is expected to be upgraded with an air-cooled condenser; these improvements are at the design level. The estimated cost for this project is $29.3 million. Once completed, the ice fog issues along the Richardson Highway should be resolved.

*Utilidor System*

The CHPP steam heat lines and condensate return lines are in a utilidor system serving the Post. The older lines are insulated with asbestos-containing material. The utilidors also include water and wastewater lines.

In 1967, the Chena River flooded the FWA utilidor system; since then, the utilidor floor has been covered with a layer of asbestos–laden dust. Those areas of the utilidor that do not contain asbestos insulation have not been isolated from those areas that do and, therefore, those areas may be contaminated as well. FWA has a program to rebuild the utilidor system over a number of years.

For purposes of this study, a basic assumption is that the steam distribution lines in the utilidor system provide freeze protection for the water and wastewater lines and that this will continue into the foreseeable future.

*Interconnection to GVEA*

FWA is interconnected to GVEA at two points:

- Fort Wainwright Generation Substation, a 7.5-megavolt-ampere (MVA), 69/12.5-kV transformer. An Army voltage regulator on the 12.5-kV side of the transformer limits the power transfer capability of the substation. The 69-kV line to the substation (feeder 21) has a 28-MW summer rating and a 32-MW winter rating.
- FWA Feeder 21 “back door” tie, a 12.5-kV feeder with a 5-MW capacity that ties the GVEA system directly into three feeders on the southwest portion of Fort Wainwright.

GVEA also directly serves the 801 Housing at the Post’s Trainor Gate entrance without interconnection to the Post electric system.

Without additional generation at FWA, the interconnection will need to be expanded to provide increased ability to purchase power from GVEA. This could be done by directly interconnecting to GVEA’s Fort Wainwright

Substation at 138 kV and building one or two distribution substations on Post. The new substations would interconnect to the existing Post electrical system.

The Post electrical distribution system does not provide for separate service to critical loads. Therefore, if it is necessary to reduce electrical loads, it is done on a facility-by-facility or feeder-by-feeder basis.

## EAFB Heat and Power Systems

### Central Heat and Power Plant

*Boiler and Steam System*

The EAFB CHPP was originally built in 1952. Figure 13 shows a schematic diagram of the existing CHPP process. The CHPP has six superheated steam, water-tube, and spreader-stoker coal-burning boilers. Four of the boilers were installed in 1951; Boilers 5 and 6 were installed in 1954. The boilers are all nameplate-rated at 120,000 lb/hr of steam at 425 psig, 625 °F.

Due to more stringent state and Federal particulate emissions standards, Boilers 2, 4, 5, and 6 have been limited by permit to a maximum steam production of less than 100,000 lb/hr Boilers 5 and 6 are in need of major overhaul or complete replacement; they are not operated beyond 80,000 lb/hr. EAFB is considering replacing Boilers 5 and 6 with new boilers located adjacent to the north of the CHPP.

The normal individual operating range for the online boilers is between 60,000 and 70,000 lb/hr. During summer months, only two boilers are needed for electrical generation and occasional steam heat. During winter operations, four to five boilers are required to meet the combined power generation and heating demand.

Five STGs provide a total rated power capacity of 25 MW. There are two 1952-vintage 2.5-MW units that are used only for standby; two 5-MW units installed in 1954 and 1969; and one 10-MW unit installed in 1987. The 5-MW and 10-MW STGs are scheduled for major maintenance every 5 years. Only STG 5 has an electronic governor, providing this unit with faster response to electrical load changes.

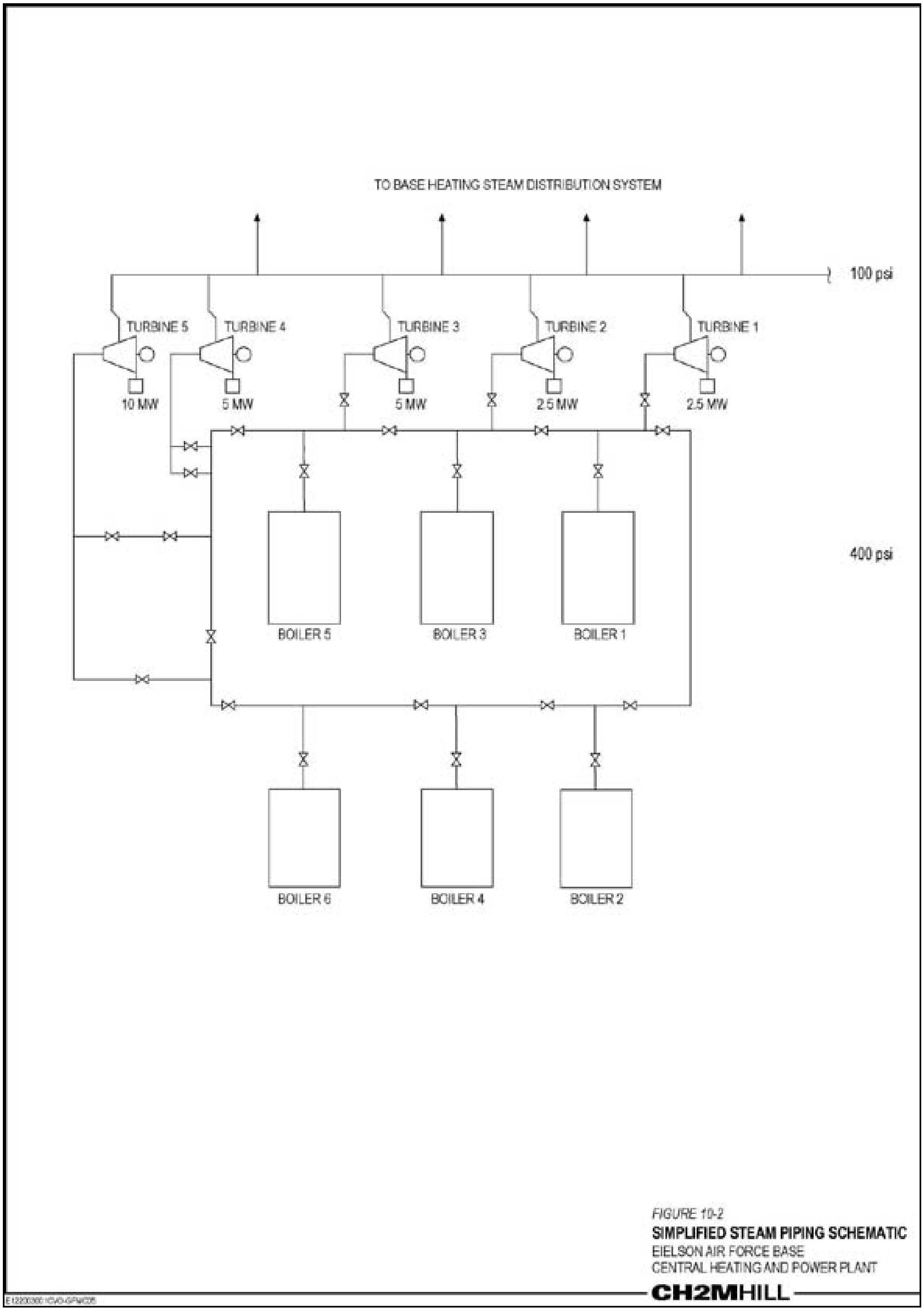



Figure 13. Existing CHPP process.

This unit is also used to support the Base loads, so it accumulates the greatest number of operating hours. It is also in need of a major overhaul. The mechanical governors on the other STGs require a great deal of maintenance to keep them adjusted and working properly.

Five diesel generators at the CHPP provide an additional rated capacity totaling 8.5 MW. Four of these generators are nameplate-rated at 1.5 MW and are installed in exterior housings located adjacent to the CHPP. The fifth unit, rated at 2.5 MW, is located in the lower level of the CHPP and provides “black start” capability in the event of a total power outage.

At full winter steam production, the makeup water system can supply 30 to 35 percent of the required boiler feedwater flow. The remaining 65 to 70 percent must come back as condensate return from the turbine condensers and the utilidor loads.

The steam supply and condensate return mains are located in the utilidor system. The steam is distributed at 100 psig in a grid system with piping originally installed in the 1940s and 1950s.

*Coal Delivery and Handling*

The primary fuel for the boilers is UCM coal. EAFB has its own rail spurs and locomotives. Once the coal cars are delivered to EAFB, CHPP personnel move the cars, unload the coal, and return the cars to the Alaska Railroad tracks.

The plant uses approximately 180,000 tons of coal per year. Coal is gravity-fed to the spreader-stoker boilers from six 200-ton bunkers, one for each boiler. The plant is also equipped to burn small supplemental quantities of refuse-derived fuel (RDF) and used oil. All six boilers have automatic soot blowers for internal cleaning. Four boilers are equipped with 20 percent slipstream baghouses for air pollution control.

In winter, the CHPP consumes 600 to 800 tons (8 to 10 rail hopper cars) of coal each day. Coal is delivered daily and is shuttled by a Base switch locomotive into the coal thaw shed where steam coils between the rails warm the frozen coal enough to allow unloading the next day. The rail hopper cars bottom-dump into two “grizzly” units beneath the rails that “screen” the coal going to the crusher. A belt conveyor system then transports the coal to 200-ton feed bunkers in front of the boilers. The overall

coal-handling system can unload and process coal at an average rate of 150 tons per hour.

Current coal operations result in significant amounts of coal dust.

### Eielson Boiler Rehabilitation Projects

The Eielson Boiler Rehabilitation Projects included total rehabilitation of Boilers 1, 2, and 3 plus the installation of new stoker feeders and soot blowers for Boilers 5 and 6. The first three boilers were completely refurbished, and Boilers 5 and 6 were significantly upgraded, all to meet current particulate emission standards.

The Boilers 1, 2, and 3 work consisted of:

- completely enclosing each boiler and removing the existing casing and the asbestos insulation covering the boilers
- removing and replacing the refractory brick with new brick
- demolishing and replacing the existing stoker feeders with new feeders
- installing new ash hoppers on all boilers
- installing new clinker grinders in lieu of the manual ash-handling system at boiler 3 only.

Other work elements included:

- installing new ash-handling piping on all boilers
- installing a new slipstream baghouse, baghouse fan, and boiler breeching for each boiler
- refurbishing the existing ID fans (including repairing the fan casing and installing new bearings and blower wheel)
- installing a new, complete over fire air (OFA) system, including a new OFA fan, ductwork, and nozzles for each boiler
- installing a complete new Boiler Master control panel and instrumentation system for each boiler, including a new variable-frequency drive control panel for each boiler's stoker feeder system
- replacing and/or repairing all internal baffles
- extensive repair of the existing traveling grate system, including repairing the grate drive bearing and drive shafts
- repairing and resurfacing the thrust bearings
- replacing the traveling grate roller pins
- installing new chain rollers
- replacing grate pad supports, chain guides, grate seals, and seal plates
- replacing the lower grate guide channels

The work on Boilers 5 and 6 included:

- Removing the existing stoker feeders and front faceplates and replacing them with new ones
- Installing new boiler master control systems
- Replacing all Boiler 6 manual soot blowers with new, motor-driven soot blowers with an automatic control system

The work was accomplished for a total cost of $18 million to 20 million.

*Coal-Handling Improvements*

A $2.9 million project is underway to upgrade the coal-handling system to OSHA standards. The work reduces coal dust from coal-handling operations to correct the OSHA violation. The scope of work includes the offloading area and several transfer points along the conveyor system.

*Emission Control Improvements*

A $23.5 million emission control project is underway to provide a full-flow baghouse system on each of the six boilers to control particulate emissions and emission opacity. The work also includes upgrading the ash collection system to a continuous-pull system with a secondary ash collection system. After installation of the baghouses, the boilers will no longer be derated because of particulate emissions concerns. The six boilers will be able to operate at their rated capacities of 120,000 lb/hr, for a total of 720,000 lb/hr.

*Utilidor System*

EAFB has 28.3 miles of utilidor system for its steam and condensate return lines and water and wastewater lines. The steam lines provide freeze protection for the water and wastewater lines.

EAFB has embarked on a multiphase, multiyear effort to rebuild the utilidor system. Phase 1 is complete, and Phases 2 and 3 are almost complete. Phase 4 has been awarded for work during summer 2004.

*Interconnection to GVEA*

The Base is electrically self-sufficient except for Charlie Battery, VOR site, Birch Lake, Engineer Hill, and Flag Hill, which receive power from GVEA.

EAFB is interconnected to GVEA through the GVEA Eielson Air Force Base Generation Substation, which consists of two 69/7.2-kV, 5/5.6-MVA transformers. These transformers limit the amount of power that can be taken from GVEA to about 12 MW. Two 5/5.6-MVA transformers are installed as spares. Connecting the spare transformers would increase the capability of the substation to about 24 MW.

GVEA service to EAFB is limited by the wire size of the 69-kV line from the GVEA Dawson Road Substation to the EAFB substation. Completion of a 138-kV line from North Pole to the Carney Substation will remove this limitation.

EAFB is installing a new main switchgear lineup for its electrical system. The new switchgear will provide main and backup busses and allow for conversion of the existing 7.2-kV three-wire system to a 12.47/7.2-kV four-wire system. The Base electrical distribution system will then be converted to a four-wire system over a number of years.

The Base electrical distribution system does not provide for separate service to critical loads. Therefore, if it is necessary to reduce electrical loads, it is done on a facility-by-facility or feeder-by-feeder basis.

All six boilers require manual bottom ash removal (twice per shift) to drag the material out of the ash pit and into the pneumatic conveying system for transport to the ash silo. Any sizable clinkers are also separated into handcarts.

The original ash system was installed in 1952. The vacuum pump for the pneumatic system is worn and losing efficiency. The ash system has been modified several times over the years, with extensive modifications since 1983. In 1996, an automated bottom ash system was installed on Boiler 3, but it has proven unworkable with the cyclic nature of the pneumatic conveyance system. Fly ash is also conveyed from the cyclone separators and slipstream baghouses to the central silo. The ash is dumped from the central silo into dump trucks for disposal.

*Stack Emission Controls*

The plant staff has removed the fly ash reinjection system from three boilers. All captured fly ash now is sent directly to the ash-handling system. This has reduced the levels of stack emissions; however, the present multiclone separators and 20 percent slipstream baghouses will not allow all of

the boilers to operate at full nameplate capacity and remain within the permit emission limits for particulate matter less than 10 micrometers in aerodynamic diameter ($PM_{10}$) particulates. Operation of the soot blowers and manual removal of bottom ash also cause stack opacities that exceed permit limits.

*Makeup Water System*

The present boiler makeup water system raw-water zeolite treatment equipment has been plagued with plugged piping, and the relatively small reserve tank is inadequate to cover a makeup water system outage or a sudden leak in the utilidor condensate return system. The treatment system is operating under high loads because of contaminants introduced to the condensate in the Base buildings and because of steam and condensate losses throughout the utilidor network. The Base plans to add three reverse osmosis systems and upgrade the condensate polisher pumps in 2004.

The current construction activities associated with the ongoing utilidor upgrade program have increased condensate leakage and losses to approximately 15 percent of total boiler feed water flow. The completed utilidor upgrades will eventually reduce these losses to about 10 percent, but in the meantime, any unexpected interruptions to condensate flow could cause a significant problem for the CHPP staff.

*Cooling and Condensing*

The condenser water pumps in the cooling pond pump house have been upgraded, but the wiring from the CHPP to the pump house does not meet standards. The pump house structure is deteriorating, and a new intake structure is needed. During summer months, the cooling pond temperatures rise to the point where they reduce the turbine generator's output capacity and efficiency, so a well pump in the vicinity of the CHPP is used for once-through cooling of the condensers. Under those conditions, the well and pump represent another single-point failure node. The hotwell pump on the condenser under Turbine 4 is worn and needs replacement. Currently, hotwell pumps for Turbine 4 are being replaced. The Base also plans to add a second water line from the pond and wells to the plant in April 2005.

The Base uses two wells during the summer months and just added a third well in 2003. The capacity and efficiency of these wells is excellent.

*Auxiliary Systems*

The fire protection sprinkler system piping in the CHPP is corroded and has developed leaks. The combustion air for the boilers is drawn from the CHPP room air and must be replaced by the makeup air units. The intakes for these makeup air units tend to freeze during severe winter weather, and the building interior becomes negatively pressurized. This affects the combustion efficiency of the individual boilers.

*Controls*

The Bailey system of boiler and turbine controls was installed in 1987. The system is presently functional, but the cost of maintaining the aging equipment is increasing, and the increased capabilities that can be offered by current technology render the Bailey system obsolete.

## FGA Heat and Power Systems

### Central Heat and Power Plant

The CHPP contains three boilers that were installed in 1954 (Figure 14). Two of the boilers were replaced in 1993 and serve as the primary boilers for meeting heat load. The third original boiler was rehabilitated in 1993 using parts, equipment, and materials from the two replaced boilers; it is used as a backup.

The boilers burn diesel fuel arctic (DFA); coal is not available.

All boilers have been well maintained and are in good condition.

The three boilers are each rated at 50,000 lb/hr of 120-psig steam. Boiler fuel is No. 2 Arctic diesel oil with a higher heating value of about 125,300 Btu/gal. Each boiler is equipped with both FD and ID fans equipped with 25-horsepower (hp) electric motors. The exception is Boiler 3, which has a 40-hp ID fan.

Steam generated at 120 psig is reduced to 60 psig and distributed to the buildings in the central cantonment area through steam piping running through underground utilidors. As at FWA and EAFB, the utilidors include water and sewer lines and rely on heat loss from the steam lines to provide freeze protection.

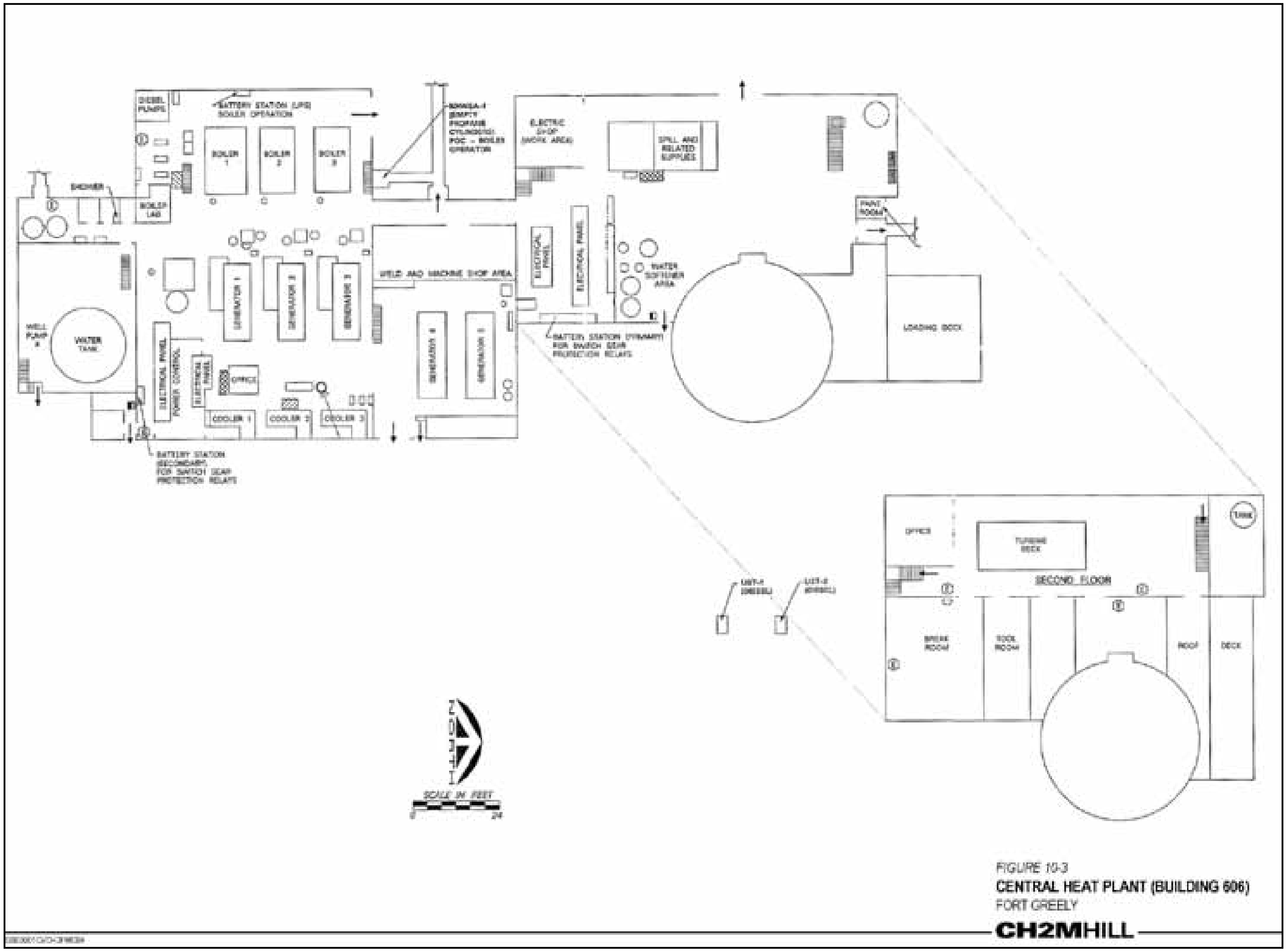



Figure 14. Three CHPP boilers installed in 1954.

Three 1-MW and one 1.25-MW diesel engine generators were installed in 1953, and a similar 1.25-MW unit was installed in 1962. All of the units are DFA-fueled and are used for peaking, if necessary, and for emergency backup.

Portions of the piping within the plant have asbestos insulation.

*Fuel Delivery and Handling*

The DFA fuel is transported by truck from North Pole. There are two 30,000-gal fuel storage tanks on base.

*Utilidor System*

Steam heat is distributed to Base facilities in utilidors. FGA has a contractor developing a plan to rehabilitate the system. Limited asbestos abatement has been done; the remaining asbestos insulation has been encapsulated. The utilidors are washed out twice a year.

*Electrical System and Interconnection to GVEA*

Electric power for FGA is delivered through a GVEA substation that is adjacent to the CHPP. The transformer is rated at 24.9/4.16 kV, 2.5 MVA. If FGA electric loads exceed the 2.5-MVA transformer rating, the CHPP diesel generators are used to meet peak loads.

Within the FGA cantonment area, the plan is to convert the existing overhead lines to underground.

GVEA service to FGA is over a distribution feeder at 24.9 kV. Service capacity on the feeder, which also serves other non-FGA loads, is limited by wire size and voltage drop. The GVEA transformer serving the CHPP is a 24.9/4.16-kV, 2.5/3.125-MVA transformer, which also limits the amount of power that can be delivered to the base.

Power is distributed to Base loads from the CHPP switchgear.

The CHPP electrical system serves the Cold Regions Test Center (CRTC) over Feeder 9, which operates at 7.2 kV. At the CHPP, there is an auto-transformer that steps the voltage up from 2.4 kV to 7.2 kV to serve this feeder. The CRTC loads have been 1 MW or less and are expected to double in the next few years. The CRTC also anticipates an additional 5-MW load

associated with its operations within the next 5 years. This load would be close to FGA in the vicinity of the GMD area. When this 5-MW load is added, it should not be served from the CHPP electrical system, as serving it off the CHPP system will require major rebuilding of the system. The method of service to the load will depend on the location.

The base electrical distribution system does not provide separate service to critical loads. Therefore, if it is necessary to reduce electrical loads, it is done on a facility-by-facility or feeder-by-feeder basis.

### CHPP Improvement Projects

To our knowledge, no improvement projects are planned for the FGA CHPP. The utilidor system is to be upgraded, including abatement of asbestos insulation on the steam and condensate return lines.

## GMD Heat and Power Systems

The GMD heat and power systems are essentially new, having been installed in the past year or two, or about to be installed.

Heat is provided by two 6.695-MMBtu-per-hour hot water boilers that burn DFA. Hot water is circulated to the various buildings in a utilidor system. Generally, hydronic unit heaters are used at individual buildings.

GMD is buying its electrical power needs from GVEA. An onsite GVEA substation has a 138/13.8-kV, 12/16/20-MVA transformer. GMD is installing four 2-MW diesel generators to be used as backup power supplies. There is also onsite fuel storage for the backup engine generators.

The system is being constructed by Fluor Alaska, and as the various facilities are completed and accepted by the MDA, they are turned over to The Boeing Company as the operator with the facilities being owned by the U.S. Army and contractor-operated.

# 8 Future Load Growth at All Installations

## Background

In making the heat and power projections discussed below, we have reviewed past load information, reviewed previous reports done for the installations regarding future steam heat and electrical loads, talked with installation personnel, and talked with GVEA about its load growth projections. We also have reviewed "future" projects that have been identified for each installation.

The loads at the Bases have been reasonably stable for a number of years. Over the past decade, the occurrence of cold weather has had more influence on loads from year to year than perceptible "load growth."

Over a period of 25 years, it is difficult to predict what missions each of the installations may have and how this will affect the need for heat and electricity. For example, FGA was slated for closure under the Base Realignment and Closure (BRAC) Act. Its training functions were realigned to FWA. It now has a new mission to support the MDA, with the GMD installation just to the south. Similarly, a Stryker Brigade is being stationed at FWA.

Prior studies used to make the load forecasts include:

- *Central Heat and Power Plant Alternatives Review, Fort Wainwright, Alaska*, U.S. Army Corps of Engineers Engineer Research and Development Center, May 2003 (FWA Alternatives Review).
- *Interim Study, Fort Wainwright, Alaska, Conversion of CHPP to Heating Only and Provide Backup Electrical Generators*, prepared for the U.S. Army Corps of Engineers Construction Engineering Research Laboratories by Science Applications International Corporation, March 2003 (FWA Heating Only Study).
- *Utility Study, Fort Wainwright, Alaska*, U.S. Army Corps of Engineers Alaska District, 95 Percent Submittal, January 2003 (FWA Utility Study).
- *Environmental and Engineering Options Study, Central Heat and Power Plant, Eielson AFB, Alaska, Final Report*, prepared for Air Force Center for Environmental Excellence by Earth Tech, Inc., September 2001 (EAFB Options Study).

- *Central Heat and Power Plant Study, Eielson AFB*, prepared for Air Force Civil Engineering Support Agency (AFCESA/CESC) by CH2M HILL, Inc., 1997 (EAFB CHPP Study).
- *Additional Options for Increased Power Reliability, Ground-Based Midcourse Missile Defense Program Ballistic Missile Defense System Test Bed, Fort Greely, Alaska*, Black & Veatch, February 2003 (GMD Study).

In addition to these studies, we obtained information about planned future projects at each installation and discussed the additional loads these might represent. The identified future projects occur not later than 2009. Existing Form 1391s were also obtained for FWA and FGA; we are generally aware that other 1391s may have been submitted or in preparation subsequent to those we were provided. To our knowledge, these 1391s will not have a significant effect on projected loads.

### Steam Heat Loads

From our discussions with base personnel regarding future loads, it appears that, generally, as new facilities and loads are added, other facilities are demolished. A good example of this is the new Bassett Hospital at FWA. Once it is completed, the old hospital will be demolished. The older building stock tends to be less energy efficient than the new building stock. Newer buildings may be larger than those buildings being demolished, but on a basewide basis, do not represent significant increases in load. The net result is that heat loads placed on the central CHPPs are expected to grow, but not at high rates.

The FWA Alternatives Review used a growth rate of 3.86 percent per year for 4 years. The FWA Heating Only Study used a 5.5 percent per year projection through 2010. The EAFB Options Study used a growth rate of 0.5 percent per year for heat load projections over the next 30 years.

It may be that in the short run, central steam heat loads will increase at rates of 4 to 5 percent per year. However, it is our opinion that this rate of growth over the long term is too high and that a 0.5 percent per year rate is more realistic for both peak hour demand and average annual load.

Our projections also assume that the relationship of annual steam heat requirements to annual peak-hour steam requirements will remain the same. That is, the load factor for steam heat will remain constant over the study period.

### Electrical Loads

Our discussions with Base personnel suggest that electrical loads will grow faster than heat loads. This trend most likely reflects the increased use of computers, control systems, etc.

The FWA Alternatives Review used a growth rate from 2003 to 2007 of 9.2 percent per year. The FWA Heating Only study used 9.4 percent per year for electricity demand through 2010. The EAFB Options Study used 2 percent per year annual growth for electricity demand.

It may be that in the short run, FWA electrical loads will increase at rates of close to 10 percent per year. However, it is our opinion that this rate of growth over the long term is too high and that a 2 percent per year rate is more realistic for both FWA and EAFB. This growth rate would be consistent with the growth rates being experienced by GVEA for its system.

For FGA, there does not appear to be reason to expect significant future electrical load growth. The projections are based on an annual growth of 0.5 percent. If the CRTC adds significant load (more than 1 MW), new service arrangements will be necessary; the existing Feeder 9 cannot support additional load without significant upgrade. CRTC is anticipating a new 5-MW load sometime during the next 5 years. If this load occurs, it will require a new electrical interconnection. The existing FGA electrical system cannot serve it.

For GMD, the projections through 2008 were developed by GMD. Projections through 2029 are based on the assumption that GMD loads will grow to 15.2 MW in 2029.

## Projected Loads

### FWA and EAFB

Table 16 lists projected steam and electricity requirements for FWA. First, peak-hour steam for heat loads is projected using the average annual rate of growth (ARG) indicated. Next, the electrical peak demand is projected.

The right-hand side of the table shows the projected average annual heat load and projected kWh requirements.

Table 16. FWA projected heat and electric demands.

| | Steam | | Electricity | | Steam | | Electricity |
|---|---|---|---|---|---|---|---|
| Year | Annual Rate of Growth (ARG) | Projected Peak Heating Demand (klbs/hr) | ARG | Projected Peak Electric Demand (MW) | ARG | Heating Steam Ann. Avg. (avg. klbs/hr) | Annual MWh |
| 2004 | | 290.0 | | 20.4 | | 173.6 | 103,067 |
| 2005 | | 290.0 | | 20.4 | | 173.6 | 103,067 |
| 2006 | | 305.0 | | 24.2 | | 182.6 | 122,266 |
| 2007 | | 320.0 | | 26.2 | | 191.6 | 132,370 |
| 2008 | 0.50% | 321.6 | 2.00% | 24.4 | 0.50% | 192.5 | 123,276 |
| 2009 | 0.50% | 323.2 | 2.00% | 24.9 | 0.50% | 193.5 | 125,742 |
| 2010 | 0.50% | 324.8 | 2.00% | 25.4 | 0.50% | 194.4 | 128,257 |
| 2011 | 0.50% | 326.4 | 2.00% | 25.9 | 0.50% | 195.4 | 130,822 |
| 2012 | 0.50% | 328.1 | 2.00% | 26.4 | 0.50% | 196.4 | 133,438 |
| 2013 | 0.50% | 329.7 | 2.00% | 26.9 | 0.50% | 197.4 | 136,107 |
| 2014 | 0.50% | 331.4 | 2.00% | 27.5 | 0.50% | 198.4 | 138,829 |
| 2015 | 0.50% | 333.0 | 2.00% | 28.0 | 0.50% | 199.4 | 141,606 |
| 2016 | 0.50% | 334.7 | 2.00% | 28.6 | 0.50% | 200.4 | 144,438 |
| 2017 | 0.50% | 336.4 | 2.00% | 29.2 | 0.50% | 201.4 | 147,326 |
| 2018 | 0.50% | 338.0 | 2.00% | 29.7 | 0.50% | 202.4 | 150,273 |
| 2019 | 0.50% | 339.7 | 2.00% | 30.3 | 0.50% | 203.4 | 153,278 |
| 2020 | 0.50% | 341.4 | 2.00% | 30.9 | 0.50% | 204.4 | 156,344 |
| 2021 | 0.50% | 343.1 | 2.00% | 31.6 | 0.50% | 205.4 | 159,471 |
| 2022 | 0.50% | 344.9 | 2.00% | 32.2 | 0.50% | 206.4 | 162,660 |
| 2023 | 0.50% | 346.6 | 2.00% | 32.8 | 0.50% | 207.5 | 165,914 |
| 2024 | 0.50% | 348.3 | 2.00% | 33.5 | 0.50% | 208.5 | 169,232 |
| 2025 | 0.50% | 350.1 | 2.00% | 34.2 | 0.50% | 209.6 | 172,616 |
| 2026 | 0.50% | 351.8 | 2.00% | 34.8 | 0.50% | 210.6 | 176,069 |
| 2027 | 0.50% | 353.6 | 2.00% | 35.5 | 0.50% | 211.7 | 179,590 |
| 2028 | 0.50% | 355.3 | 2.00% | 36.2 | 0.50% | 212.7 | 183,182 |

The data in Table 17 provides the same analysis for EAFB. For FWA:

- Peak heat loads are projected to grow by about 22 percent from 2004 through 2028, from 290,000 to 355,300 lb/hr.
- Peak electrical demands are projected to grow from 20.4 to 36.2 MW, an increase of 82 percent. (The existing STG capacity is 20 MW, and the GVEA interconnection capacity is 12.5 MW.) In 2004, a new Simulator Building comes online, then the new Bassett Hospital in 2006, the Stryker Brigade Combat Team and Family Housing in 2007, followed by demolition of the old Bassett Hospital in 2008.

For EAFB, it can be seen that:

- Peak heat loads are projected to grow from 281,400 to 317,200 lb/hr, an increase of about 13 percent.
- Peak electrical demands are projected to grow from 18.5 to 29.7 MW, an increase of about 60 percent. (The existing STG capacity is 25 MW, and the GVEA interconnection capacity is 12.5 MW.)

### FGA

Table 18 lists projected loads for FGA.

Based on our discussions with FGA Directorate of Public Works (DPW) representatives, we project no growth beyond the 1996 heat load levels for FGA. New facility loads likely will be offset with facility demolition. These projections are specific to the cantonment area and do not include heat loads for the old North Post.

The electrical projections show a 0.5-MW increase in load from 2004 to 2005, the result of new CRTC loads. Minimal electrical demand load growth (0.5 percent a year) is projected after that. The projection includes existing CRTC loads. (Note that the existing GVEA interconnection has a capacity of 3.125 MW, which is the projected peak demand under -60 °F conditions for 2003. The existing 5.5 MW of standby engine generators is used for peak shaving and backup.)

A separate projection was made for a 5-MW CRTC load because this load will have to be served independently of the existing FGA electrical system.

Table 17. EAFB projected heat and electric demands.

| | Steam | | Electricity | | Steam | | Electricity |
|---|---|---|---|---|---|---|---|
| Year | Annual Rate of Growth (ARG) | Projected Peak Heating Demand (klbs/hr) | ARG | Projected Peak Electric Demand (MW) | ARG | Heating Steam Ann. Avg. (avg. klbs/hr) | Annual MWh |
| 2004 | 0.50% | 281.4 | 2.00% | 18.5 | | 119.6 | 83,802 |
| 2005 | 0.50% | 282.8 | 2.00% | 18.9 | | 120.2 | 85,478 |
| 2006 | 0.50% | 284.2 | 2.00% | 19.2 | | 120.8 | 87,188 |
| 2007 | 0.50% | 285.6 | 2.00% | 19.6 | | 121.4 | 88,931 |
| 2008 | 0.50% | 287.1 | 2.00% | 20.0 | 0.50% | 122.0 | 90,710 |
| 2009 | 0.50% | 288.5 | 2.00% | 20.4 | 0.50% | 122.6 | 92,524 |
| 2010 | 0.50% | 289.9 | 2.00% | 20.8 | 0.50% | 123.2 | 94,375 |
| 2011 | 0.50% | 291.4 | 2.00% | 21.2 | 0.50% | 123.8 | 96,262 |
| 2012 | 0.50% | 292.9 | 2.00% | 21.6 | 0.50% | 124.5 | 98,187 |
| 2013 | 0.50% | 294.3 | 2.00% | 22.1 | 0.50% | 125.1 | 100,151 |
| 2014 | 0.50% | 295.8 | 2.00% | 22.5 | 0.50% | 125.7 | 102,154 |
| 2015 | 0.50% | 297.3 | 2.00% | 23.0 | 0.50% | 126.3 | 104,197 |
| 2016 | 0.50% | 298.8 | 2.00% | 23.4 | 0.50% | 127.0 | 106,281 |
| 2017 | 0.50% | 300.2 | 2.00% | 23.9 | 0.50% | 127.6 | 108,407 |
| 2018 | 0.50% | 301.8 | 2.00% | 24.4 | 0.50% | 128.2 | 110,575 |
| 2019 | 0.50% | 303.3 | 2.00% | 24.8 | 0.50% | 128.9 | 112,786 |
| 2020 | 0.50% | 304.8 | 2.00% | 25.3 | 0.50% | 129.5 | 115,042 |
| 2021 | 0.50% | 306.3 | 2.00% | 25.9 | 0.50% | 130.2 | 117,343 |
| 2022 | 0.50% | 307.8 | 2.00% | 26.4 | 0.50% | 130.8 | 119,690 |
| 2023 | 0.50% | 309.4 | 2.00% | 26.9 | 0.50% | 131.5 | 122,084 |
| 2024 | 0.50% | 310.9 | 2.00% | 27.4 | 0.50% | 132.1 | 124,525 |
| 2025 | 0.50% | 312.5 | 2.00% | 28.0 | 0.50% | 132.8 | 127,016 |
| 2026 | 0.50% | 314.0 | 2.00% | 28.5 | 0.50% | 133.5 | 129,556 |
| 2027 | 0.50% | 315.6 | 2.00% | 29.1 | 0.50% | 134.1 | 132,147 |
| 2028 | 0.50% | 317.2 | 2.00% | 29.7 | 0.50% | 134.8 | 134,790 |

Table 18. FGA projected heat and electric demand.

| Year | FGA | | | | | | CRTC | |
|---|---|---|---|---|---|---|---|---|
| | Steam | | | | Electricity | | Electricity | |
| | Annual Rate of Growth (ARG) | Projected Peak Heating Demand (klbs/hr) | ARG | Heating Steam Ann. Avg. (klbs/hr) | ARG | Peak w/ Existing CRTC (MW)[1] | ARG | New CRTC Peak (MW)[2] |
| 2004 | 0.00% | 26.3 | 0.00% | 20.2 | 6.07% | 3.6 | 0.00% | - |
| 2005 | 0.00% | 26.3 | 0.00% | 20.2 | 6.07% | 4.1 | 0.00% | - |
| 2006 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.1 | 0.00% | - |
| 2007 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.1 | 0.00% | - |
| 2008 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.2 | 0.00% | 5.0 |
| 2009 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.2 | 0.50% | 5.0 |
| 2010 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.2 | 0.50% | 5.1 |
| 2011 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.2 | 0.50% | 5.1 |
| 2012 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.2 | 0.50% | 5.1 |
| 2013 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.3 | 0.50% | 5.1 |
| 2014 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.3 | 0.50% | 5.2 |
| 2015 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.3 | 0.50% | 5.2 |
| 2016 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.3 | 0.50% | 5.2 |
| 2017 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.4 | 0.50% | 5.2 |
| 2018 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.4 | 0.50% | 5.3 |
| 2019 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.4 | 0.50% | 5.3 |
| 2020 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.4 | 0.50% | 5.3 |
| 2021 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.4 | 0.50% | 5.3 |
| 2022 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.5 | 0.50% | 5.4 |
| 2023 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.5 | 0.50% | 5.4 |
| 2024 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.5 | 0.50% | 5.4 |
| 2025 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.5 | 0.50% | 5.4 |
| 2026 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.6 | 0.50% | 5.5 |
| 2027 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.6 | 0.50% | 5.5 |
| 2028 | 0.00% | 26.3 | 0.00% | 20.2 | 0.50% | 4.6 | 0.50% | 5.5 |

1 Represents FGA and CRTC loads served by FGA electrical system.

2 Represents projected new CRTC load that would be served independently of the FGA electrical system.

### GMD

Table 19 lists projected loads for GMD. The installation is being constructed to use hot water boilers and to purchase its electricity from GVEA. The heat demand projection is based on an annual growth rate of 1 percent per year.

Table 19. GMD projected heat and electric demand.

| Year | Steam | | | | Electricity | |
|---|---|---|---|---|---|---|
| | Annual Rate of Growth (ARG) | Projected Peak Heating Demand (MMBtu) | ARG | Heating Steam Ann. Avg. (MMBtu) | ARG | Peak (MW) |
| 2004 | 0.00% | 5.2 | 0.00% | 4.0 | 20.11% | 4.8 |
| 2005 | 0.00% | 5.2 | 0.00% | 4.0 | 20.11% | 5.8 |
| 2006 | 0.00% | 5.2 | 0.00% | 4.0 | 20.11% | 6.9 |
| 2007 | 0.00% | 5.2 | 0.00% | 4.0 | 20.11% | 8.3 |
| 2008 | 1.00% | 5.3 | 1.00% | 4.0 | 2.00% | 10.0 |
| 2009 | 1.00% | 5.3 | 1.00% | 4.1 | 2.00% | 10.2 |
| 2010 | 1.00% | 5.4 | 1.00% | 4.1 | 2.00% | 10.4 |
| 2011 | 1.00% | 5.4 | 1.00% | 4.2 | 2.00% | 10.6 |
| 2012 | 1.00% | 5.5 | 1.00% | 4.2 | 2.00% | 10.8 |
| 2013 | 1.00% | 5.5 | 1.00% | 4.2 | 2.00% | 11.0 |
| 2014 | 1.00% | 5.6 | 1.00% | 4.3 | 2.00% | 11.3 |
| 2015 | 1.00% | 5.6 | 1.00% | 4.3 | 2.00% | 11.5 |
| 2016 | 1.00% | 5.7 | 1.00% | 4.4 | 2.00% | 11.7 |
| 2017 | 1.00% | 5.7 | 1.00% | 4.4 | 2.00% | 12.0 |
| 2018 | 1.00% | 5.8 | 1.00% | 4.5 | 2.00% | 12.2 |
| 2019 | 1.00% | 5.9 | 1.00% | 4.5 | 2.00% | 12.4 |
| 2020 | 1.00% | 5.9 | 1.00% | 4.6 | 2.00% | 12.7 |
| 2021 | 1.00% | 6.0 | 1.00% | 4.6 | 2.00% | 12.9 |
| 2022 | 1.00% | 6.0 | 1.00% | 4.6 | 2.00% | 13.2 |
| 2023 | 1.00% | 6.1 | 1.00% | 4.7 | 2.00% | 13.5 |
| 2024 | 1.00% | 6.2 | 1.00% | 4.7 | 2.00% | 13.7 |
| 2025 | 1.00% | 6.2 | 1.00% | 4.8 | 2.00% | 14.0 |
| 2026 | 1.00% | 6.3 | 1.00% | 4.8 | 2.00% | 14.3 |
| 2027 | 1.00% | 6.3 | 1.00% | 4.9 | 2.00% | 14.6 |
| 2028 | 1.00% | 6.4 | 1.00% | 4.9 | 2.00% | 14.9 |

The electrical demand through 2007 is based on information obtained from GMD and GVEA. Beyond 2008, the peak electrical demand is projected to grow at 2 percent per year. This results in a projected peak demand of 14.9 MW in 2028. (Note that the GVEA interconnection has a capacity of 20 MW. GVEA is currently limited to 10 MW of transmission capacity to GMD and is in the process of permitting a transmission line upgrade(s) to increase the capacity to the area to 80 MW.)

# 9 Existing Reliability for Heat and Power

The installations' had not explicitly specified their reliability requirements. Complete outages of the CHPPs and power plants are rare. It is more common to experience outages on the overhead electrical system feeders or on a steam distribution line. In some cases, the electrical systems are looped, allowing outages to be isolated and service to be restored. Generally, the steam systems are looped, allowing outages to be isolated and repaired without significant interruption to service.

Recent studies have identified exposures to single-contingency points of failure, and efforts have been made or are planned to correct these exposures.

The installations have acceptable levels of reliability through redundancy and backup systems, obtained through a combination of onsite firm steam and power generation and backup generation; where installed, uninterruptible power supply (UPS) systems; and interconnections with GVEA.

For purposes of this study, the historical levels of service reliability are assumed to be sufficient for the future.

## Existing Installation Approach for Heat and Power

### Steam Generation

The FWA and EAFB CHPPs each have six boilers of comparable size, and during expected peak steam heat demands, operating three to four boilers can meet the peak. This allows for one boiler to be out of service, one boiler to be on cold backup, and one boiler to be on warm backup or sharing steam production with the three operating boilers.

Historically, this configuration has provided a high degree of reliability in steam supply. While some of the support systems have represented single-contingency points of failure, the exposure has not resulted in re-occurring outages. Recent or planned repairs have addressed many of these exposures.

EAFB also has installed auxiliary heating plants to provide backup for both the CHPPs and utilidor systems.

It is our understanding that for those individual facilities at each installation that have no backup heat source, contingency and evacuation plans exist to provide for the safety and protection of personnel.

### Electric Power Generation

FWA and EAFB have taken the same approach to electric power generation; both installations have five STGs. At FWA, STG Unit 2 has been abandoned in place, resulting in only four STGs available for generation. EAFB's five units are of different sizes, but do provide redundancy for reliability under normal circumstances.

Peak electrical demands at both installations are such that loss of an STG during peak demand requires that power be purchased from GVEA or backup engine generators be brought online or both. In addition, the Bases have installed UPS systems for loads that are particularly sensitive to power quality and transient conditions on their power supply.

### Backup Power Generation

All of the installations except FWA have backup engine generator capacity to provide power for peaking, during onsite generation outages, or when GVEA outages occur. FWA relies on purchases from GVEA to back up its CHPP generation. At EAFB, the backup generation is not intended to carry the entire installation load. At FGA and GMD, generation is sufficient to meet all of the installations' electrical loads independent of outside supply.

It is possible to install equipment (engine jacket water heaters, battery chargers, lubricating oil heaters, and pre-alarms to the engine annunciation package) to provide quick-start capability (no more than 10 seconds to online generation) to diesel generators. To our knowledge, this has only been done at GMD. At the other installations, the backup engine generators can be brought online in a few minutes.

If loads cannot tolerate outages (whether for a few cycles, seconds, or minutes), the appropriate solution is a UPS system installed as close to the load as practical. The UPS can provide continuous power conditioning and prevent momentary outages and transients. Short of UPS provisions and onsite generation capability, reliability levels greater than those provided by either the CHPPs or GVEA system are not obtainable. There are UPSs for critical loads at all four installations. It has not been determined if all critical loads have UPS systems. Figure 15 shows how backup can be pro-

vided for electrical loads using switchgear, generation sets, and UPS packages.

FWA also has a "back door" distribution feeder intertie to the GVEA system, allowing FWA to place load on GVEA as needed.

## GVEA System Reliability

GVEA's reliability in supplying power to the installations has been assessed through GVEA's outage records. For the 1999 through September 2003 period, GVEA provided electric service to its customers 99.97 percent of the time. This rate is comparable to the reliability performance of electric utilities in the lower 48 states. It does, however, represent about 2.6 hours per customer of outage time per year.

The approaches to providing increased reliability are primarily redundancy, flexibility to respond to various contingencies, maintenance, monitoring, and testing.

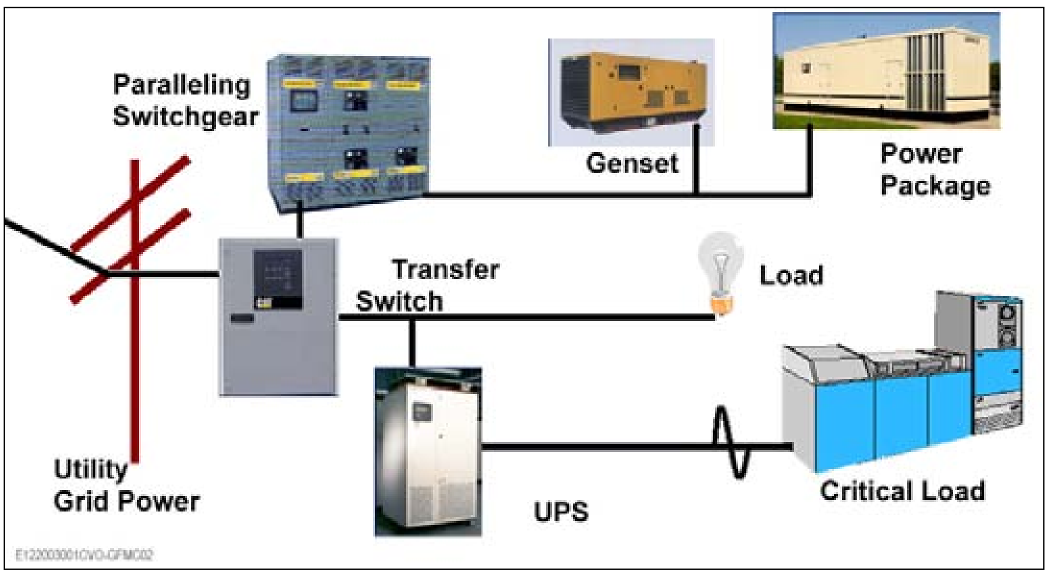



Figure 15. Backup for electrical loads.

GVEA has a reasonable degree of redundancy in its power supply; it has a number of units in different locations that can be used to meet load, and it has capacity in reserve to replace generation that is out of service, whether planned or forced. The use of the Railbelt Intertie—a single-contingency pathway—to import energy into the Fairbanks area creates an exposure to short-term outages when the Intertie trips out of service.

GVEA has responded to this by building a second circuit for the northern portion of the Intertie, operating a shedding load scheme, and recently installing the BESS. The second circuit for the northern portion of the Intertie has eliminated the prior single-contingency exposure for transmission outages between Healy and Fairbanks. GVEA also keeps generation capacity on standby so that it can be brought online in a 15- to 20-minute timeframe. The use of load shedding has proven to be a more economical solution for GVEA than maintaining spinning reserves (expensive, oil-fired reserves).

GVEA also has a multi-voltage mobile spare transformer that can be moved to any of its substations and used to provide service if a transformer fails. As discussed below, a single transformer serves each installation.

For further discussion on GVEA's reliability, see Chapter 4, "Golden Valley Electric Association," Historical Outages" (p 47) and "GVEA Backup Power Generation" (p 52).

### GVEA Interconnection to FWA

Within the Fairbanks area, the GVEA transmission/distribution system is configured to provide backup capability at the distribution level from adjacent substations and looped distribution feeders.

Service to FWA is constrained by the 7.5-MVA GVEA transformer at the Fort Wainwright Power Plant substation and by the FWA voltage regulator. The back door distribution feeder intertie is limited to 5 MVA of capacity. Both of these interties have exposure to a single-contingency outage.

FWA does not typically separate from the GVEA system when GVEA experiences abnormal conditions. This results more from lack of electric system protective relays to sense the abnormalities and separate than from FWA preferences.

FWA uses UPS systems for critical loads.

### GVEA Interconnection to EAFB

At EAFB, the GVEA system interconnection to the base is through a single 12/16/20-MVA transformer. There are two EAFB 6.125-MVA transformers that step the voltage down to 7.2 kV. These two transformers limit the in-

terconnection to 12.5 MVA. Two additional 6.125-MVA spare transformers could be connected to increase the capacity of the Intertie to the 20 MVA of the GVEA transformer. The GVEA transformer represents an exposure to a single-contingency outage. EAFB is currently self-sufficient with on-site generation to meet its power supply needs.

EAFB has its protective relays set so that it separates from GVEA whenever GVEA experiences a transient condition on its system. This rapid separation helps to ensure that EAFB generation is not adversely affected by generation-load mismatches on the GVEA system. The new main plant electrical switchgear installation may allow the relay sensitivity to be decreased, but the issue of EAFB generation not being able to support GVEA system generation-load mismatches will remain.

EAFB uses UPS systems for critical loads.

### GVEA Interconnection to FGA and GMD

The GVEA transmission line serving the FGA and GMD area is a single line from GVEA's Carney Substation south. An outage anywhere along the line results in a complete loss of transmission to those areas south of the outage. GVEA has no plans to add a second circuit to the FGA/GMD area. It does conduct regular maintenance inspections of the line, monitor line loading with its supervisory control and data acquisition (SCADA) system, and has protective relaying in place to protect the line's conductors and equipment. If an outage occurs, the only option to ensure high-reliability service is for end users to have standby generation onsite to serve critical loads.

The GVEA interconnection to FGA is over a GVEA distribution feeder and through a 3.125-MVA single transformer, which is an exposure to a single-contingency outage. Normally, all FGA's needs are met by imported power (FWA and GVEA). FGA has 5.5 MW of onsite engine generator capacity to meet its loads if an outage on the GVEA system occurs. FGA uses UPS systems for critical loads.

GMD is interconnected to the GVEA system through a 12/16/20-MVA transformer served from the GVEA Jarvis Creek Substation. GMD purchases its electrical needs from GVEA. GMD has, or is installing, sufficient onsite standby engine generator capacity to meet its loads during a GVEA outage. GMD also uses UPS systems for critical loads.

# 10 Environmental Considerations

The Chapter discusses power plant permitting issues as related to air quality issues in the Alaska and the Fairbanks area and permitting of transmission lines and fuel lines. New facilities will most likely require either an environmental assessment (EA) or an environmental impact statement (EIS). Given the nature of the project's contemplated, new heat and power plant, alternatives would most likely require an EIS.

## Overview of EIS Process

When a decision is made to proceed with a project, it needs to be sufficiently defined to allow discussion and consultation with the interested agencies about the issues the project will encounter. Known issues are described below.

### Notice of Intent

Once the initial data gathering, analysis, and consultation have been completed the lead National Environmental Policy Act (NEPA) agency would prepare a Notice of Intent (NOI) to be published in the Federal Register and local newspapers. The NOI would include a description of the proposed action and alternatives, description of the public scoping process, and names and addresses of key contacts.

### Project Scoping

Project scoping is a set period of time for agencies, organizations and citizens to identify potential issues related to the proposed action and alternatives. Although the Notice of Intent usually contains minimal information, many project proponents have additional documentation available for public review. For example, GVEA completed an EA prior to initiating the EIS scoping process for its Northern Intertie Project. Examples of potential issues that may be raised for a utility corridor include:

- Creating open corridors across wildlife habitat, loss of habitat, changes in recreational experiences, and increased hunting pressures
- aviation safety, especially where a transmission line crosses major rivers
- visual impacts to private property owners, tourists, and scenic views
- loss of property value through establishment of rights-of-way

- impacts to avian species through collisions with the transmission line
- loss of wetland and riparian habitat from pipeline trenching or transmission towers
- impacts from electromagnetic fields (EMF) from transmission lines
- impacts to fire management (positive and negative)
- potential of spills from a pipeline.

In addition to receiving written comments, public meetings in the vicinity of the project would also be held. These public meetings can be conducted in two parts, an initial open house that provides information about the project and a more formal part that takes verbal comments from interested parties and citizens.

### Draft EIS

A Draft EIS (DEIS) is a written document that evaluates the purpose and need for the proposed action; a range of reasonable alternatives; the affected environment; the potential environmental, social, and economic impacts associated with the proposed action and alternatives; and appropriate mitigation measures to minimize or avoid impacts. The DEIS is designed to provide sufficient evidence and analysis for determining the magnitude of these impacts and identifying ways to minimize or mitigate any potential harm to the environment based on the best information available.

### Public Comment on Draft EIS

Following the publication of the DEIS, there is a 60-day public review period. Written comments on the DEIS are accepted throughout the public review period for inclusion in the Final EIS (FEIS). Public meetings should also be planned that allows additional comments to be presented verbally.

### Final EIS

Verbal and written comments received during the DEIS review periods are evaluated and the document revised, as appropriate. The FEIS includes a "public responsiveness summary," which summarizes comments received during the public comment period and identifies how these comments have been addressed. The FEIS also has a section that summarizes the key differences between the DEIS and the FEIS. Some FEIS may also include a summary of mitigation proposed and/or recommended. There is a 30-day public review period following the issuance of the FEIS.

### Record of Decision

Once the public review period for the FEIS has been completed and the reviewed, the Federal Lead Agency will prepare a Record of Decision (ROD). The ROD includes: (1) decisions regarding the proposed project, (2) the alternatives that were considered in the decision-making process, (3) identification of the environmentally preferred alternative, and (4) a statement about whether all practicable means to avoid or minimize environmental harm have been adopted for the preferred alternative and, if not, why they were not.

### Permits and Approvals

After the ROD has been published Federal agencies can issue all required permits and approvals for the project. In most cases state and local agencies also wait until the ROD is published before they issue permits. Note that although the Federal agencies will incorporate recommended mitigation either included in the EIS or the ROD, state and local agencies may or may not include the mitigation measures or they may include more stringent mitigation or other conditions in their permits.

## Air Quality Impacts

### Overview

Air pollutant regulations will require power producing projects to include emission controls as part of the project. The actual controls required will depend on the size and type of source and the type of fuel proposed for the project as well as the results of computer modeling of impacts of the project. In addition, locating a source in a management/non-attainment or maintenance area as well as locating near a Class I area, such as Denali Park, will impact the type of controls required.

*Air Quality Permitting Requirements in Alaska*

Construction, reconstruction, or modification of power producing equipment in Interior Alaska requires an air quality construction permit. This permit will approve construction of specific equipment and set limits on pollutant emissions from that equipment as well as require demonstrations of compliance with those limits after startup. The air pollutant limits reflect requirements published by Federal, state and local regulations.

An operating permit will also be required after start-up of the equipment authorized to be constructed. An operating permit presents the air pollutant emission limits as well as monitoring, recordkeeping, and reporting requirements that are required over the 5-year life of the permit.

Federally funded projects must also conduct a demonstration of conformity with the applicable implementation plan if the proposed project exceeds certain thresholds and is located in a designated management/non-attainment or maintenance area.

*Construction Permit*

The ADEC has primacy in administering the construction permit program for all sources of air pollutants in Alaska. At the present time, the ADEC administers all construction permits under the same program. However, Alaska regulations are presently being rewritten to develop two construction permit programs: one for major sources that are subject to Federal permitting requirements as well as State of Alaska permitting requirements, and a second more streamlined permit program for smaller facilities that are only subject to State of Alaska permitting requirements. This rewrite of the Alaska air quality regulations will not change emission limits and is not expected to impact any proposed solutions for long-term energy supply for the GFMC.

Considering the type of facilities that would be constructed for power production, most any construction involving new facilities or reconstruction or modification of existing facilities will require some level of a construction permit.

*Construction* involves building a new facility or adding new equipment to an existing facility. *Reconstruction* implies a project in which the capital expenditures exceed 50 percent of the capital cost of building a new facility. Reconstruction requires a construction permit even though the potential to emit regulated air pollutants is decreasing as a result of the project. A *Modification* involves making a physical change or change in operation to the facility that results in any increase in the potential to emit a regulated air pollutant.

For fuel burning sources, the threshold for requiring a construction permit is equipment with a rated capacity of 100 million Btu (MMBtu) input to the system or with a rated capacity of 50 MMBtu input to the system if a control device is needed to meet the pollutant emission limits set by

Alaska regulations. Due to this low threshold, it is anticipated that any new installation considered by the project will require a construction permit.

All construction permits will address pertinent Alaska regulations. In addition, Federal regulations that are applicable to the facility are included. If the project is considered a new major source or a major modification of a major source, the EPA requires a permitting process called New Source Review (NSR).

A *major stationary source* is any source belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year or more of a regulated air pollutant or any other source which emits or has the potential to emit 250 tons per year of a regulated air pollutant. Two categories of sources in the 28-source category list could potentially be involved in the project. They are: “fossil-fuel-fired steam electric plants of more than 250 MMBtu per hour heat input” and “fossil-fuel boilers or combination of boilers totaling more than 250 MMBtu per hour heat input.” These types of facilities are major if they have the potential to emit 100 tons or more of a regulated air pollutant. All other types of power producing sources such as CTs are considered major if they have the potential to emit 250 tons or more of a regulated air pollutant. A combined cycle gas turbine using a heat recovery steam generator (HRSG) and with the ability to fire more than 250 MMBtu per hour is included in the category of fossil-fuel-fired steam electric plants and would be considered a major source if it has the potential to emit 100 tons per year or more of a regulated air pollutant.

A *major modification of a major source* involves a physical change or a change in the method of operation of a major stationary source which would result in a significant net emissions increase of a regulated pollutant. A significant increase is an increase above the thresholds presented in Table 20. A net increase implies that reductions and increases in emissions of a pollutant as a result of the project are included in calculating the amount of the increase. When determining if a proposed project requires NSR, all previous minor pollutant increases since the last NSR are considered and the total compared to the significance thresholds.

Table 20. Threshold increase requiring new source review at a major source.

| Pollutant | Threshold Increase (tons/yr) |
|---|---|
| Carbon Monoxide | 100 |
| Oxides of Nitrogen | 40 |
| Sulfur Dioxide | 40 |
| Total Particulate Matter | 25 |
| Particulate Matter less than 10 microns in diameter | 15 |
| Volatile Organic Compounds | 40 |
| Lead | 0.6 |
| Fluorides | 3 |
| Sulfuric Acid Mist | 7 |
| Total Reduced Sulfur Compounds, including hydrogen sulfide | 10 |
| Hydrogen Sulfide | 10 |
| Reduced Sulfur compounds, including hydrogen sulfide | 10 |
| Municipal Waste Combustor Organics, measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans | 0.0000035 |
| Municipal Waste Combustor Metals, measured as particulate matter | 15 |
| Municipal Waste Combustor Acid Gases, measured as sulfur dioxide and hydrogen chloride combined | 40 |
| Any increase in actual emissions of a regulated air contaminant not listed above, except for hazardous air contaminants, organic vapors, and ammonia | --- |
| Municipal Waste Landfill Emissions measured as non-methane organic compounds | 50 |
| If located within 10 kilometers of a Class I area, any increase in actual emissions of a regulated air contaminant that would result in an ambient concentration of that contaminant greater than one microgram per cubic meter (24-hour average) in the Class I area | |

The NSR process is divided into two types of permits, the prevention of significant air quality deterioration (PSD) permit, which addresses pollutants for which the area is in compliance with the National Ambient Air Quality Standards (NAAQS) and the management/NAA permit, which addresses pollutants for which the area is not in compliance with the NAAQS or is designated as a maintenance area.

A maintenance area is an area that previously was designated as a management/NAA, but subsequently has demonstrated compliance with the NAAQS. In addition to demonstrating compliance, there must be an EPA approved maintenance plan for staying in compliance to be designated a maintenance area. An area will remain a maintenance area for many years before officially being designated an attainment area.

In Interior Alaska, only the Fairbanks area is not in compliance with a NAAQS, carbon monoxide (CO). However, recent monitoring has shown

the area is in compliance and a maintenance plan is being developed. Being designated a maintenance area typically will not significantly change requirements from those required for a management/NAA, since agencies usually incorporate the management/NAA requirements into the maintenance plan.

*Prevention of Significant Deterioration (PSD) Permit*

The first step in the PSD permit process is to determine applicability of the process to the project. Assuming the project involves a major stationary source or major modification to an existing major stationary source, the PSD permit process applies to each air pollutant that is potentially released in significant amounts and for which the area is designated as attaining the NAAQS. For example, a project at a major source located in the Fairbanks CO management/NAA would require the PSD process for any pollutant for which the project causes a significant net increase (cf. Table 21), except for CO. Any potential increase of CO as a result of the project will require review under the management/NAA permit process. One strategy is to propose control technologies and other restrictions as part of the construction permit. The main provisions of a PSD permit require the project to:

- apply the best available control technology (BACT)
- perform an air quality analysis demonstrating the project does not cause or contribute to a violation of the NAAQS and associated PSD increment
- analyze the impacts to soils, vegetation, and visibility
- not adversely impact a Class I area
- provide public notice and a public comment period.

*Best Available Control Technology (BACT) Analysis*

The PSD process requires a BACT analysis for each new or modified pollutant source. The BACT analysis is conducted on a case-by-case basis taking into account individual aspects of a project such as location. Each proposed control technology is reviewed by evaluating the associated energy, environmental, economic and other costs, and the reduced-emissions benefit that the technology would provide. The ADEC then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for the pollutant.

Review of each proposed control technology is conducted using what is called a top-down ranking process. The top-down process provides that all

available control technologies be ranked in descending order of control effectiveness. The applicant first examines the most stringent or "top" alternative. That alternative is established as BACT unless the applicant demonstrates, and the ADEC agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable. If the most stringent technology is eliminated, the next most stringent technology is considered, and so on, until BACT is determined.

*Ambient Air Quality Impact Analysis*

The main purpose of the ambient air quality analysis is to demonstrate that new emissions emitted from a proposed major stationary source or major modification will not cause or contribute to a violation of any applicable NAAQS or PSD increment. The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere (Table 21). A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant.

If the project proposes to emit the pollutant in a significant amount from a new major stationary source, or causes a significant net emissions increase from a major modification, a separate air quality analysis must be submitted for each regulated pollutant. Regulated pollutants include both criteria pollutants (pollutant for which a NAAQS exists) and non-criteria pollutants (other pollutants regulated by the EPA for which no NAAQS exists).

In general, the ambient air quality impact analysis involves an assessment of existing air quality and predictions of ambient concentrations that will result from the proposed project and future growth associated with the project. Assessing existing air quality can involve computer modeling or using ambient monitoring results. In cases where ambient monitoring has not been conducted, the ADEC may choose to require pre-construction monitoring to establish the existing ambient concentration of a pollutant being analyzed or to establish meteorological information for the project area. Pre-construction monitoring can significantly impact a project schedule. In addition to the time required to design and install the monitoring system, pre-construction monitoring may be required to be conducted for up to a year. To minimize the impact to a project schedule, the applicant typically presents a description of the proposed project to the ADEC very early in the project schedule and initiates discussions to determine if pre-

construction monitoring will be required to establish existing air quality information.

In general, the ambient air quality impact analysis involves an assessment of existing air quality and predictions of ambient concentrations that will result from the proposed project and future growth associated with the project. Assessing existing air quality can involve computer modeling or using ambient monitoring results.

Table 21. National ambient air quality standards.

| Pollutant | Primary | Secondary |
|---|---|---|
| Sulfur Oxides | | |
| Annual Arithmetic Mean | 0.03 ppm[a] | |
| 24-hour Average | 0.14 ppm[b] | |
| 3-hour Average | | 0.50 ppm[b] |
| $PM_{10}$ (Particulate matter less than 10 microns in aerodynamic diameter) | | |
| Annual Arithmetic Mean | 50 $\mu g/m^3$ [a] | 50 $\mu g/m^3$ [a] |
| 24-hour Average | 150 $\mu g/m^3$ [c] | 150 $\mu g/m^3$ [c] |
| $PM_{2.5}$(Particulate matter less than 2.5 microns in aerodynamic diameter) | | |
| Annual Arithmetic Mean | 15 $\mu g/m^3$ | 15 $\mu g/m^3$ |
| 24-hour Average | 65 $\mu g/m^3$ [d] | 65 $\mu g/m^3$ [d] |
| Carbon Monoxide | | |
| 8-hour Average | 9 ppm[b] | |
| 1-hour Average | 35 ppm[b] | |
| Ozone | | |
| 8-hour Average | 0.08 ppm[e] | 0.08 ppm[e] |
| 1-hour Average | 0.12 ppm[f] | 0.12 ppm[f] |
| Nitrogen Dioxide | | |
| Annual Arithmetic Mean | 0.053 ppm[a] | 0.053 ppm[a] |
| Lead | | |
| Calendar Quarter Arithmetic Mean | 1.5 $\mu g/^{m3a}$ | 1.5 $\mu g/m^3$ [a] |

Note:
ppm = parts per million parts
μg/m3 = micrograms per cubic meter
[a]not to be exceeded.
[b]not to be exceeded more than once per calendar year.
[c]99th percentile.
[d]98th percentile.
[e]average of the annual fourth-highest daily maximum.
[f]number of days is not to be exceeded more than once per calendar year.

In cases where ambient monitoring has not been conducted, the ADEC may choose to require pre-construction monitoring to establish the existing ambient concentration of a pollutant being analyzed or to establish meteorological information for the project area. Pre-construction monitoring can significantly impact a project schedule. In addition to the time required to design and install the monitoring system, pre-construction monitoring may be required to be conducted for up to a year. To minimize the impact to a project schedule, the applicant typically presents a description of the proposed project to the ADEC very early in the project schedule and initiates discussions to determine if pre-construction monitoring will be required to establish existing air quality information.

It is very probable that pre-construction monitoring will be required to site a major source in areas outside of Fairbanks. In general, very little monitoring has been conducted in these areas and it is logical that the ADEC will require monitoring to gain baseline information and/or meteorological data for modeling.

Monitoring for pollutant concentration and for meteorological data has been conducted in many areas of Fairbanks including the major military bases. As a result, the possibility of needing pre-construction monitoring is less, but it still exists. This is demonstrated by the pre-construction monitoring required for a recent construction project at the Williams North Pole Refinery. For that project, it was determined the area had unique meteorological conditions and local meteorological information was needed. In general, the ADEC will require pre-construction monitoring where significant questions about baseline pollutant concentrations or meteorological information needed to demonstrate compliance.

Predictions of ambient concentrations as a result of a proposed project are determined with dispersion modeling techniques using EPA approved computer models. Prior to commencing any extensive analysis, the applicant should submit a modeling protocol for review and approval. The modeling protocol details the proposed approach to demonstrating compliance with the NAAQS and PSD increments. It includes the proposed computer models, the meteorological data, and the specific inputs to the computer models.

*Additional Impacts Analysis*

A PSD permit application must include an additional impacts analysis for each pollutant subject to the PSD process. This analysis involves assessing

the impacts of air, ground, and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

The analysis is conduced by first estimating the quantity of emissions as a result of permanent residential, commercial, and industrial growth expected as a result of the project. An ambient air quality analysis is then conducted using EPA approved computer models and including emissions from sources that have been permitted but not yet built as well as emissions from the proposed project and the associated growth. The results are added to the background levels for the area to develop an estimate of the total ground-level concentrations of pollutants.

To assess the impact on soils and vegetation, an inventory of soil and vegetation types found in the impact area is developed. The inventory focus is on vegetation with any commercial or recreational value. Literature is then reviewed to determine if the ground-level concentrations of pollutants determined from modeling are expected to impact each species.

The visibility impairment analysis is focused on impacts that occur within the area affected by applicable emissions. A visibility impairment analysis includes a determination of the visual quality of the area, an initial screening of emission sources to assess the possibility of visibility impairment, and if warranted, a more in-depth analysis involving computer modeling.

Typically, all or parts of the analysis detailed above are not needed when determining impacts in Class II area. In these cases, secondary air quality standards (Table 21) are used to determine these impacts while the more detailed analysis is required when the project will significantly impact a Class I area.

*Class I Area Impact Analysis*

Federal Class I areas include international parks, national wilderness areas, national memorial parks which exceed 5,000 acres in size, and national parks that exceed 6,000 acres in size. They are specified by the Clean Air Act and in Alaska include Denali National Park and Bering Sea, Simeonof and Tuxedni National Wilderness Areas. Of these areas, only Denali National Park could be impacted by projects in the northern portion of Interior Alaska.

Class I areas are protected from degradation by increments for certain pollutants. As with PSD increments, Class I increments are the maximum increases in ambient pollutant concentrations allowed over the baseline concentrations. However, the Class I increments are much more stringent than PSD increments. In addition, the Federal Land Manager (FLM) of each Class I area defines specific air quality related values (AQRVs) to protect that specific Class I area. The FLM also develops appropriate criteria to determine an adverse impact on the AQRVs.

At a minimum, the EPA policy requires an AQRV impact analysis for project emissions that cause an increase in the ambient concentration of a pollutant of more than 1 microgram per cubic meter in the Class I area. However, a FLM may set lower thresholds for conducting an AQRV analysis to protect sensitive resources. An AQRV analysis is usually not required when the project area is more than 200 kilometers from a Class I area.

The Class I area impact analysis therefore is defined on a case-by-case basis. Although computer modeling is required to demonstrate compliance with Class I increments in all cases, the scope of the AQRV analysis (if required) will depend on input from the FLM for the Class I area. Historically, the FLM for Denali National Park has been actively involved in the process and is very sensitive to any increases in air pollutants that could degrade visibility in and around the park.

*Public Notice and Public Comment*

The process of obtaining a PSD permit requires the owner to submit an application to the ADEC describing the proposed project and including the above described analyses. The ADEC reviews the application to be sure that all applicable regulations are met by the project. Assuming all applicable regulations and requirements are being met, the ADEC will prepare a draft permit for public comment. Although at this stage of the process the ADEC takes responsibility for defending the proposed permit, the owner may be requested to submit additional information to support the proposed project. Upon responding to public comments, the ADEC issues a final construction permit.

### Management/Non-Attainment Area Permit

The management/NAA permit process applies to emissions of pollutants located in an area that has been designated as not attaining the NAAQS for those pollutants. The management/NAA permit process is similar to the

PSD permit process however, there are differences in determining applicability of the process as well as the requirements of the process. The following discussion presents the differences in the two processes.

The management/NAA permit process has a different definition for a major stationary source. For the Fairbanks CO management/NAA, a major source is any stationary source that has the potential to emit 100 tons per year or more of CO. For other management/NAAs, the determination of major source depends on the pollutant and the severity of the management/NAA. This is in contrast to the PSD process in which a major source is defined as having the potential to emit 250 tons per year of a regulated pollutant or is one of 28 source categories and has the potential to emit 100 tons per year of a regulated pollutant.

The management/NAA permit process requires a lowest achievable emission rate (LAER) analysis instead of the BACT analysis required for PSD. The management/NAA permit process also requires that the owner of the project obtain emissions reductions or offsets at a ratio specified in the State Implementation Plan (SIP) as a condition of approval of the permit. Finally, the applicant must certify that all other sources owned by the applicant in the state are complying with all applicable regulations of the Clean Air Act.

Note that although the Fairbanks area is not officially in compliance with the NAAQS for CO at the present time, recent monitoring data have shown the area to be in compliance. Applications have been submitted to the EPA requesting re-designation of the area to a maintenance area and a maintenance plan is being prepared. However, the ADEC will typically include the management/non-attainment requirements, such as emission offsets, as part of the maintenance plan. As a result, being designated a maintenance area will not significantly change the requirements from those required for a management/NAA.

*Lowest Achievable Emission Rate Analysis*

LAER is the most stringent of either the most stringent emission limitation specified in the SIP for the source category or the most stringent emission limitation achieved by the same class or category of source. Unlike BACT, LAER does not consider economic, energy, or other environmental factors, although LAER costs can be considered in unusual circumstances.

The LAER analysis involves reviewing the SIP to determine if LAER has been set for the type of source being built or modified and determining the

most stringent limitation achieved in practice by a similar class or category of source. The most stringent of these two limitations effectively is considered BACT unless the applicant can demonstrate that the most stringent is not technically feasible.

*Emission Offsets*

Emission reductions must be obtained as a condition of approval of the management/NAA permit. The reductions must offset the emissions increase from the new source or modification and provide a net air quality benefit. Offsets should be located as close to the proposed site as possible, however, the ADEC will ultimately decide if a specific offset can be used. Offsets normally involve reducing emissions from a nearby source such as by adding a control device or limiting operations. In accordance with the State of Alaska SIP, the offset ratio is 1 for 1, which means that for every ton increase in the management/NAA pollutant, the project will be required to obtain an offset of 1 ton. This offset ratio will also be required if the area is designated a maintenance area.

### Air Quality Operating Permit

An air quality operating permit (Title V permit) will be required for operation of a power producing facility that has the potential to emit more than 100 tons per year of a criteria pollutant or is subject to New Source Performance Standards (NSPS) or NESHAPs regulations (including NESHAPs by source category). The Title V permit presents the air pollutant emission limits and associated monitoring, recordkeeping, and reporting requirements established by previous operating permits or construction permits. Application for a Title V permit may be submitted with the construction permit application or separately as long as it is at least one year prior to startup of the facility. For modification of a facility with an existing operating permit, the applicant only needs to request that the construction permit conditions be rolled into the existing operating permit.

### Federal Conformity Requirements

Federal conformity requirements for Federal projects other than transportation projects apply to those Federal actions located in nonattainment or maintenance areas, such as Fairbanks for carbon monoxide, CO. The remainder of Interior Alaska presently is considered in attainment of all NAAQS. Table 22 lists the thresholds for requiring a conformity demonstration. In addition the SIP for a state may require lower thresholds. The

threshold for requiring a conformity demonstration for emissions of carbon monoxide in the Fairbanks CO management/NAA (or maintenance area) is 100 tons per year. If a project has gone through the NAA permitting process, general conformity analysis is not required.

The Federal conformity demonstration requires conducting computer modeling to determine impacts of both direct and indirect emissions of the pollutant. To demonstrate conformity, the results of the computer modeling must show that the action does not cause or contribute to any new violation of a standard or increase the frequency or severity of any existing violation of a standard.

This modeling is very similar to the ambient impact analysis required by NSR. The applicant avoids the conformity demonstration by demonstrating emissions as a result of the project will be less than the thresholds requiring conformity.

Table 22. Thresholds requiring conformity determinations (tons per year).

| Management/NAA | Threshold |
|---|---|
| Ozone (VOCs or NOx) | |
| Serious management/NAA | 50 |
| Severe management/NAA | 25 |
| Extreme management/NAA | 10 |
| Other ozone management/NAA | 100 |
| VOCs | 50 |
| $NO_2$ | 100 |
| CO—all management/NAA | 100 |
| Sulfur dioxide or nitrogen oxides—all management/NAA | 100 |
| $PM_{10}$ | |
| Moderate management/NAA | 100 |
| Serious management/NAA | 70 |
| Lead—all management/NAA | 25 |
| Maintenance areas | |
| Ozone (NOx), $SO_2$, or $NO_2$—all maintenance areas | 100 |
| Ozone (VOCs): | |
| Maintenance areas inside an ozone transport region | 50 |
| Maintenance areas outside an ozone transport region | 100 |
| CO—all maintenance areas | 100 |
| $PM_{10}$—all maintenance areas | 100 |
| Lead—all maintenance areas | 25 |

## Regulations

Air quality regulations affecting the study area have been published by the EPA, ADEC, and the FNSB. The following information presents a brief summary of regulations that could affect construction, reconstruction, or modification of power producing equipment in Interior Alaska.

### *Regulations Promulgated by the EPA*

The construction permit and ultimately the operating permit for a new, reconstructed or modified power producing facility will reflect the air pollution standards set by EPA, the State of Alaska, and the local regulatory agency. The EPA has promulgated standards in two general groups which reflect the type of pollutant regulated. NSPS regulate criteria pollutants, which are those for which a NAAQS exists. National Emission Standards for Hazardous Air Pollutants (HAPs) address non-criteria pollutants.

#### *40 CFR Part 60—New Source Performance Standards*

The NSPS are published in 40 CFR Part 60 and are presented by type of source. They address criteria pollutants and are applicable to new, reconstructed, or modified facilities constructed after a specific date. The following presents summaries of NSPS regulations that could impact a power producing project. These brief summaries do not include all the regulations affecting unique situations such as emerging technology projects or projects that involve burning unique fuels such as coal refuse and solid-derived fuels.

##### Subpart D—Fossil Fuel Fired Steam Generators.

Subpart D is applicable to fossil fuel fired steam generating units of more than 73 megawatts heat input rate (greater than 250 MMBtu per hour input) and constructed after 17August 1971. Table 23 lists summary emission limits set by Subpart D.

##### Subpart Da—Electric Utility Steam Generating Units.

Subpart Da is applicable to each electric utility steam generating unit capable of combusting more than 73 megawatts (250 MMBtu per hour) heat input of fossil fuel and constructed after 18 September 978. A steam electric utility generating unit is defined as one that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power

distribution system for sale. Table 24 lists summary emission limits set by Subpart Da.

### Subpart Db—Industrial-Commercial-Institutional Steam Generating Units.

Subpart Db is applicable to each steam generating unit that has a heat input capacity of greater than 29 megawatts (100 MMBtu per hour) and constructed after 19 June 1986. Steam generating units meeting the requirements of Subpart Da are not subject to Subpart Db. Table 25 lists summary emission limits set by Subpart Db.

### Subpart Kb—Volatile Organic Liquid Storage Vessels.

Subpart Kb is applicable to volatile organic liquid storage vessels (including petroleum liquid storage vessels) constructed after 23 July 1984. Table 26 lists summary emission limits set by Subpart Kb. The regulations present tank volumes in cubic meters ($m^3$) and vapor pressures in kilo-Pascals (kPa). More conventional units are provided in parenthesis.

### Subpart Y—Coal Preparation Plants.

Subpart Y is applicable to coal preparation plants processing more than 200 tons per day and affects thermal dryers, pneumatic coal-cleaning equipment, coal process and conveying equipment, coal storage systems, and coal transfer and loading systems constructed after 24 October 1974. Gases from thermal dryers cannot contain more than 0.031 grains of particulate matter per dry standard cubic foot or exhibit 20 percent opacity or greater. Gases from pneumatic coal cleaning equipment cannot contain more than 0.018 grains of particulate matter per dry standard cubic foot or exhibit 10 percent opacity or greater. Gases from other equipment cannot exhibit 20 percent opacity or greater.

### Subpart GG—Stationary Gas Turbines.

Subpart GG applies to all stationary gas turbines with a heat input at peak load equal to greater than 10 MMBtu per hour, based on the lower heating value of the fuel fired, and constructed after 3 October 1977. Subpart GG is a relatively old subpart and is scheduled to be rewritten in the near future. The following information on emission limits is presented; however, when Subpart GG is rewritten, emission limits are expected to be lower to reflect present technology in turbine design and air pollution control systems.

Table 23. Fossil-fuel-fired steam generators, 40 CFR Subpart D.

| Pollutant | Maximum Emission Rate | CEMS Requirements |
|---|---|---|
| *Particulate Matter* | 0.10 lb/MMBtu | Not Required |
| *Opacity* | 20% opacity[1] | Required[2] |
| *Sulfur Dioxide*[3] | | *see notes 2 & 4* |
| Firing Liquid Fossil Fuels | 0.80 lb/MMBtu | Required |
| Firing Solid Fossil Fuels | 1.2 lb/MMBtu | Required |
| Firing Combination of Solid and Liquid Fuels | Prorated[5] | Required |
| *Nitrogen Oxides* | | *see note 6* |
| Firing Gaseous Fossil Fuels | 0.20 lb/MMBtu | Required |
| Firing Liquid Fossil Fuels | 0.30 lb/MMBtu | Required |
| Firing Solid Fossil Fuels (except lignite) | 0.70 lb/MMBtu | Required |
| Firing Lignite | 0.60 lb/MMBtu | Required |
| Firing 25% (or more) coal refuse with | Exempt[7] | Not required |

Notes:

1. Except for one six-minute period per hour of not more than 27 percent opacity.
2. Continuous emission monitoring systems are not required for opacity and sulfur dioxide when burning only gaseous fuels.
3. Compliance with the sulfur dioxide standard is based on the total heat input from all fossil fuels burned, including gaseous fuels.
4. If a sulfur dioxide standard is met without using a control device, sulfur dioxide emissions can be measured by fuel sampling and analysis instead of a CEMS.
5. The maximum emission rate of sulfur dioxide from firing a combination of solid and liquid fuels is prorated by the percent of each fuel fired.
6. If the initial performance tests show that less than 70 percent of the applicable standard is being emitted, a CEMS for nitrogen oxides is not required.
7. When at least 25 percent, by weight, of coal refuse is burned in combination with a fossil fuel or wood residue, the standard for nitrogen oxides does not apply.

Table 24. NSPS electric utility steam generating units, 40 CFR Subpart D.

| Pollutant | Potential Combustion Concentration |
|---|---|
| *Particulate Matter* | |
| Solid Fuel | 7.0 lb/MMBtu |
| Liquid Fuels | 0.17 lb/MMBtu |
| Sulfur Dioxide | from sulfur content of fuel, as received |
| *Nitrogen Oxides* | |
| Gaseous fuels | 0.67 lb/MMBtu |
| Liquid fuels | 0.72 lb/MMBtu |
| Solid fuels | 2.30 lb/MMBtu |
| Pollutant | Maximum Emission Rate |
| Opacity | 20% opacity[1] |
| Solid, liquid, or gaseous fuel | 0.03 lb/MMBtu |
| Solid fuels[2] | 1% of potential combustion concentration |

| Pollutant | Potential Combustion Concentration |
|---|---|
| Liquid fuels[2] | 30% of potential combustion concentration |
| *Sulfur Dioxide* | |
| Firing Solid Fuels | 1.20 lb/MMBtu *and* 10% of potential combustion concentration *or* 30% of potential combustion concentration if emissions are less than 0.60 lb/MMBtu. |
| Firing Liquid or Gaseous Fuels | 0.80 lb/MMBtu *and* 10% of potential combustion concentration *or* 100% of potential combustion concentration if emissions are less than 0.20 lb/MMBtu. |
| Firing a combination of fuels | Prorated[3] |
| Nitrogen Oxides | |
| Firing Coal-derived Gaseous Fuels | 0.50 lb/MMBtu |
| Firing All Other Gaseous Fuels | 0.20 lb/MMBtu |
| Firing Coal-derived Liquid Fuels | 0.50 lb/MMBtu |
| Firing Shale Oil | 0.50 lb/MMBtu |
| Firing All Other Liquid Fuels | 0.30 lb/MMBtu |
| Firing Coal-derived Solid Fuels | 0.50 lb/MMBtu |
| Firing Sub-bituminous Coal | 0.50 lb/MMBtu |
| Firing Bituminous Coal | 0.60 lb/MMBtu |
| Firing Anthracite Coal | 0.60 lb/MMBtu |
| Firing All Other Fuels | 0.60 lb/MMBtu |

Notes:

1. Except for one six-minute period per hour of not more than 27 percent opacity.
2. Compliance with the particulate matter emission limitation constitutes compliance with the percent reduction requirements for particulate matter.
3. The maximum emission rate of sulfur dioxide from firing a combination of fuels is prorated by the percent of each fuel fired.

Continuous Emission Monitoring Systems are required for opacity, sulfur dioxide, and nitrogen oxides with the following exceptions:

1. Continuous emission monitoring systems are not required for opacity when burning only gaseous fuels.
2. Continuous emission monitoring systems are not required for sulfur dioxide when burning only natural gas.

Table 25. NSPS electric utility steam generating units, 40 CFR Subpart Da

| Pollutant | Maximum Emission Rate |
|---|---|
| *Sulfur Dioxide* | |
| Firing Coal | 1.2 lb/MMBtu[1] *and* 10% of potential combustion concentration. |
| Firing Oil | 0.80 lb/MMBtu[1] *and* 10% of potential combustion concentration[2]. |
| Firing a Combination of Coal and Oil | Same as above, prorated by fuel type. |
| *Particulate Matter* | |
| Firing Coal or<br>Coal with 10% or less Other Fuels | 0.05 lb/MMBtu |
| Coal with greater than 10% Other Fuels | 0.10 lb/MMBtu |

| Pollutant | Maximum Emission Rate |
|---|---|
| Firing ≤30% Coal and other Solid Fuels and <250 MMBtu/hr Input Heat Capacity | 0.20 lb/MMBtu |
| Firing Oil and Mixtures of Oil with Other Fuels and Using an $SO_2$ Control Device[2] | 0.10 lb/MMBtu |
| Firing ≤ 30% Wood and Mixtures of Wood with Other Fuels, Except Coal | 0.10 lb/MMBtu |
| Firing Less Than 30% Wood and Mixtures of Wood with Other Fuels, Except Coal | 0.20 lb/MMBtu |
| Firing Municipal Solid Waste (MSW) or MSW with 10% or less Other Fuels | 0.10 lb/MMBtu |
| Opacity | 20% opacity[3] |
| *Nitrogen Oxides* | |
| Firing Coal, Oil, or Natural Gas | 0.20 lb/MMBtu |
| Firing Natural Gas or Distillate Oil in Excess of 30% and Has a Low Heat Release Rate[4] | 0.10 lb/MMBtu |

Notes:

1. No credit is provided for the heat input from the combustion of natural gas, wood, or other fuels input to the affected facility.
2. Percent reduction requirements are not applicable to facilities burning oil with a sulfur content of 0.5 weight percent or less.
3. Except for one six-minute period per hour of not more than 27 percent opacity.
4. Low heat release rate means a rate of 70,000 Btu/hour-$ft^3$ or less.

**Continuous Emission Monitoring Systems** are not required, however, extensive testing is needed to demonstrate compliance with the applicable standards.

**Table 26. Liquid storage tank emission controls, 40 CFR Part 60 Subpart Kb (after 23 July 1984; reflects 15 October 2003, revision).**

| Storage Tank Volume | True Vapor Pressure (TVP) (Based on average storage temperature during warmest calendar month) | | | |
|---|---|---|---|---|
| | TVP < 5.2 kPa (TVP < 0.75 psia) | 5.2 kPa < TVP < 27.6 kPa (0.75 psia < TVP < 4 psia) | 27.6 kPa < TVP < 76.6 kPa (4 psia < TVP < 11.1 psia) | TVP > 76.6 kPa (TVP > 11.1 psia) |
| 0 $meters^3$ < Volume < 75 $meters^3$ (0-472 bbls or 0-20,000 gal) | No Controls Required | No Controls Required | No Controls Required | No Controls Required |
| 75 $meters^3$ < Volume < 151 $meters^3$ (472-950 bbls or 20,000-40,000 gal) | No Controls Required | No Controls Required | Note 1 | Vapor Recovery |
| Volume > 151 $meters^3$ (> 950 bbls or > 40,000 gal) | No Controls Required | Note 1 | Note 1 | Vapor Recovery |

Notes:

1. Required:
   a. Internal floating roof with: foam or liquid filled seal, OR double seal, OR mechanical shoe seal.
   OR
   b. External floating roof with: primary seal (mechanical shoe or liquid-mounted seal) AND secondary seal.
   OR
   c. Vapor Recovery (closed vent system with a control device)
2. Alaska DEC regulations are the same as above with the exception of storage vessels located at the Port of Anchorage.

Subpart GG limits emissions of nitrogen oxides from stationary gas turbines with a heat input at peak load of 100 MMBtu per hour or greater to no more than 75 parts per million. This amount is adjusted for the manufacturer's rated heat rate and an allowance for fuel-bound nitrogen with the following equation:

$$NOx\ Standard\ (\%) = 0.0075\ (14.4/Y) + F$$

Where:
Y = the manufacturer's rated heat rate at manufacturer's rated load (kJ/watt-hr).
F is defined as:

| Fuel-bound Nitrogen (% by weight) | F (N= % nitrogen content) |
|---|---|
| $N \leq 0.015$ | 0 |
| $0.015 < N \leq 0.1$ | 0.04 (N) |
| $0.1 < N \leq 0.25$ | 0.004 + 0.0067 (N–0.1) |
| $N > 0.25$ | 0.005 |

Subpart GG also limits emissions of nitrogen oxides from stationary gas turbines with a heat input at peak load of 10 MMBtu per hour (but less than 100 MMBtu per hour) to no more than 150 parts per million. This amount is adjusted for the manufacturer's rated heat rate and an allowance for fuel-bound nitrogen as described above, but using the following equation:

$$NOx\ Standard\ (\%) = 0.0150\ (14.4/Y) + F$$

Regenerative cycle gas turbines with a heat input <=100 MMBtu per hour are exempt from the Subpart GG nitrogen oxides standard.

Subpart GG limits the sulfur content of any fuel burned in a stationary gas turbine to 0.8 percent by weight. In addition, gases from a stationary gas turbine cannot contain more than 0.015 percent sulfur dioxide by volume at 15 percent oxygen and on a dry basis.

*40 CFR Part 61—National Emission Standards for Hazardous Air Pollutants (NESHAPs)*

NESHAPs presented in 40 CFR Part 61 are standards written in response to the Clean Air Act (1970) and address pollutants individually. This approach had many problems and only addressed eight pollutants before it was discontinued. None of the standards presented in 40 CFR Part 61 (NESHAPs) are expected to impact power producing projects. The Clean Air Act Amendments of 1990 mandated regulations be written for hazardous air pollutants by source category.

*40 CFR Part 63—NESHAPs by Source Category*

NESHAPs by source category set minimum air pollutant standards called Maximum Achievable Control Technology (MACT) standards. In essence, the MACT standard sets a level that assures that all major sources of hazardous air pollutants (HAPs) achieve the level of control at least as stringent as that already achieved by the top 12 percent sources (or top five sources if less than 30 in the source category) in each source category or subcategory. A major source of HAP emissions is a plant site than emits or has the potential to emit any singe HAP at a rate of 10 tons per year or more or any combination of HAP at a rate of 25 tons per year or more.

Subpart YYYY-NESHAPs for Stationary CTs.

Subpart YYYY applies to stationary CTs with a rated peak power output of 1 megawatt or larger located at a major source of HAP emissions. Subpart YYYY is presently a signed final rule, but has not been promulgated in the Federal Register as of the date of this document.

Subpart YYYY primarily addresses formaldehyde, but concentrations of other HAPs are also reduced when controlling formaldehyde emissions. This subpart applies to stationary CTs that are lean premix gas- or oil-fired stationary CTs or are diffusion flame gas- or oil-fired stationary CTs. Subpart YYYY limits the concentration of formaldehyde to 91 parts per billion by volume and dry or less at 15 percent $O_2$.

Subpart DDDDD-NESHAPs for Industrial/Commercial/Institutional Boilers and Process Heaters.

Subpart DDDDD applies to boilers and process heaters and is a proposed regulation. A final regulation has not been promulgated; therefore, the emissions limits or applicability aspects presented may change in the final regulation.

Subpart DDDDD has specific definitions for large units, small units, and limited use units. Large units are watertube boilers and process heaters with heat input capacities greater than 10 MMBtu per hour. Small units are firetube boilers or boilers and process heaters with heat input capacities less than or equal to 10 MMBtu per hour. A limited use unit is a large unit with capacity utilization less than or equal to 10 percent. Table 27 lists the emission limits proposed by Subpart DDDDD.

Table 27. NESHAPs by Source Category, Liquid Storage Tank Emission Controls, 40 CFR Part 60 Subpart Kb (after 23 July 1984; reflects 15 October 2003, revision).

| Source/Subcategory | Particulate Matter (lbs/MM Btu) | or | Total Selected Metals (lbs/MM Btu) | Hydrogen Chloride (lbs/MM Btu) | Mercury (lbs/MM Btu) | Carbon Monoxide (ppm@3% O2) |
|---|---|---|---|---|---|---|
| *New Boiler or Process Heater* | | | | | | |
| Solid Fuel, Large Unit | 0.026 | or | 0.0001 | 0.02 | 0.000003 | 400 |
| Solid Fuel, Small Unit | 0.026 | or | 0.0001 | 0.02 | 0.000003 | ---- |
| Solid Fuel, Limited Use | 0.026 | or | 0.0001 | 0.02 | 0.000003 | 400 |
| Liquid Fuel, Large Unit | 0.03 | ---- | ---- | 0.0005 | ---- | 400 |
| Liquid Fuel, Small Unit | 0.03 | ---- | 0.0009 | ---- | ---- | ---- |
| Liquid Fuel, Limited Use | 0.03 | ---- | ---- | 0.0009 | ---- | 400 |
| Gaseous Fuel, Large Unit | ---- | ---- | ---- | ---- | ---- | 400 |
| Gaseous Fuel, Small Unit | ---- | ---- | ---- | ---- | ---- | ---- |
| Gaseous Fuel, Limited Use | ---- | ---- | ---- | ---- | ---- | 400 |
| *Existing Boiler or Process Heater* | | | | | | |
| Solid Fuel, Large Unit | 0.07 | or | 0.001 | 0.09 | 0.000007 | ---- |
| Solid Fuel, Small Unit | ----- | ---- | ---- | ---- | ---- | ---- |
| Solid Fuel, Limited Use | 0.2 | or | 0.001 | ---- | ---- | ---- |
| Liquid Fuel, Large Unit | ---- | ---- | ---- | ---- | ---- | ---- |
| Liquid Fuel, Small Unit | ---- | ---- | ---- | ---- | ---- | ---- |
| Liquid Fuel, Limited Use | ---- | ---- | ---- | ---- | ---- | ---- |
| Gaseous Fuel | ---- | ---- | ---- | ---- | ---- | ---- |

## State of Alaska and Local Regulations

The State of Alaska regulations for fuel burning equipment address emissions of particulate matter, emissions of sulfur oxides, and opacity. These regulations are primarily for sources smaller than those impacted by Federal regulations and are not as stringent as Federal regulations. The following information presents emission limits that could potentially affect construction of new or modified power producing equipment.

Particulate matter emissions may not exceed 0.05 grains per standard cubic foot of exhaust gas except for a steam generating plant fueled by coal and rated at less than 250 MMBtu per hour input, or a steam generating plant fueled by municipal wastes. In this case, the particulate matter emissions may not exceed 0.10 grains per standard cubic foot of exhaust gas. At a coal preparation facility, emissions from a thermal drying unit may not exceed 70 milligrams of particulate matter per cubic meter of exhaust gas at standard conditions. In addition, emissions of particulate matter from a

pneumatic coal-cleaning unit may not exceed 40 milligrams of particulate matter per cubic meter of exhaust gas at standard conditions.

Sulfur compound emissions, expressed as sulfur dioxide, from fuel burning equipment may not exceed 500 parts per million averaged over a period of three hours. Visible emissions from fuel-burning equipment may not reduce visibility through the exhaust effluent by greater than 20 percent for a total of more than three minutes in any 1 hour with the exception that process emissions other than from a pneumatic cleaner at a coal preparation facility may not reduce visibility by more than 20 percent averaged over 6 minutes. In addition, emissions from a pneumatic cleaner at a coal preparation facility may not reduce visibility by more than 10 percent averaged over 6 minutes.

A minor source construction permit is required by the ADEC for fuel burning sources larger than 100 MMBtu/hr input or 50 MMBtu/hr for sources using a control device to reduce pollutant emissions. As part of the construction permit application the applicant most likely will have to demonstrate compliance with the NAAQS and PSD increments. This modeling analysis follows the same modeling approach and computer models as required by the NSR permitting process.

The FNSB Code is the only local regulation affecting stationary sources of air pollution. It primarily addresses open burning requirements and limits and is not expected to significantly impact a new or modified power producing project in the area.

*Typical Controls Required for Emissions of Sulfur Dioxide ($SO_2$)*

CTs burning liquid or gaseous fuels typically do not use control devices to control emissions of $SO_2$; these emissions are usually controlled using low sulfur fuels. This is true no matter what regulation or requirement is being considered, including the modeling requirements, best available control technology (BACT) analyses, and conformity requirements. For sources less than approximately 20 MW that only have to meet the Alaska Department of Environmental Conservation (ADEC) requirements of 500 ppm, the sulfur content of the fuel needs to be 0.5 percent by weight or less such as #2 diesel. However, modeling results can show that lower sulfur content is needed. Sources larger than approximately 20 MW which require a BACT analysis could easily need to burn ultra-low sulfur fuel such as naphtha, if the fuel is available and economically feasible to burn.

Boilers burning liquid or gaseous fuels also use fuel sulfur content to control emissions of $SO_2$ in the same manner as turbines. However, boilers burning coal typically will require dry scrubbing to reduce emissions of $SO_2$. Dry scrubbing essentially converts the $SO_2$ to sulfate particles which are collected in a baghouse. Since coal-fired-boilers typically need a baghouse to control emissions of particulate matter, much of the control system is already in place. CFBs make this process less expensive since limestone can be used. The limestone is calcined in the combustion process. In a conventional stoker boiler, more expensive lime must be injected.

*Typical Controls Required for Emissions of Nitrogen Oxides (NOx)*

Control requirements for emissions of NOx are very difficult to predict. The quantity of NOx caused by combustion turbines burning liquid and gaseous fuels can range widely depending on the make and model of the turbine. The type of liquid fuel burned can also affect the quantity of NOx produced since heavier distillate fuels contain more fuel-bound nitrogen and will create more NOx. As a result, some turbines generating less than 10 MW may be required to go through the BACT process for NOx while another turbine generating more than 30 MW may not emit enough NOx to require BACT. In addition, technology in both turbine design as well as NOx control systems is rapidly changing. In some cases BACT can be avoided by adding water or steam injection to assist in avoiding the formation of NOx. In cases where BACT cannot be avoided, add-on controls using catalysts to convert NOx to gaseous nitrogen (not regulated) will most likely be required. Note that water and/or steam injection may not be feasible during cold temperatures experienced in Interior Alaska as a result of the potential to form ice fog.

Boilers burning liquid and gaseous fuels as well as coal-fired stoker boilers release enough NOx to require a BACT analysis will most likely be required to use catalytic systems to reduce emissions of NOx. As in the case of reducing emissions of $SO_2$, reducing emissions of NOx from CFBs burning coal is less expensive than reducing emissions from stoker boilers since non-catalytic systems can be used with CFBs. The use of CFB boilers with NCR will generally yield sufficient NOx reduction that SCR is not necessary.

Oxidation systems are not typically used because the coal fouls the catalyst and because of the presence of sulfur, which results in acidic $SO_3$, which is detrimental to downstream equipment.

*Typical Controls Required for Emissions of Carbon Monoxide (CO)*

Emissions of CO are a result of incomplete combustion of the fuel burned. Since incomplete combustion essentially reduces the energy produced by the system, manufacturers of boilers and turbines are constantly attempting to improve combustion efficiency to maximize system output. The temperature of the combustion reaction plays an important role in the formation of CO. As temperature is increased, CO emissions are typically reduced while NOx emissions increase. The design of a system typically involves a trade-off between emissions of CO and emissions of NOx. As a result, emissions of CO vary widely depending on the manufacturer similar to emissions of NOx.

CO catalyst technology for CT emissions has improved significantly in recent years and can typically be demonstrated to be technically and economically feasible for CT systems requiring BACT for CO. As a result, CO catalysts are typically needed on all types of CT systems producing as low as 10 MW or greater.

*Typical Controls Required for Emissions of Particulate Matter ($PM_{10}$ and $PM_{2.5}$)*

Add-on control devices for emissions of particulate matter (PM) from CTs are not economically feasible due to the large volumes of exhaust gas that need to be treated. Since particulate matter released by these systems is primarily ash, reduction in PM is accomplished by burning low ash fuels such as light range distillate fuels or gaseous fuels. This is true for virtually all sizes of CTs.

Coal-fired boilers typically have high volumes of ash and will usually require a baghouse or an electrostatic precipitator to reduce emissions of PM. This is true for virtually all commercial and industrial sizes of coal-fired boilers typically encountered. CFBs burning coal reduce the cost of electrostatic precipitator control systems since much of the ash is removed in the process thereby minimizing the size of the electrostatic precipitator control system. Baghouse control systems are sized on the basis of gas volume, and ash loading does not influence the sizing of the baghouse.

*Other Control Device Considerations*

Other factors can determine control device requirements when siting a new power plant or modifying an existing power plant. These factors in-

clude local meteorological conditions and facility design which affect the results of an ambient impact analysis, as well as the BACT or lowest achievable emissions rate (LAER) analyses. Unusual local meteorological conditions or facility designs that cause significant downwash may require more stringent control systems. In any case, the NAAQS and increments must be met. BACT and LAER processes are designed to change as both system and control technology advances are made. As a result, control requirements will change as these technologies improve.

## Pipeline and Electric Transmission Line Siting and Permitting

The discussion describes the regulatory setting and process for siting, permitting, construction and operation of a pipeline and/or an electric transmission line (hereafter referred to as the utility line) in Alaska. The assumption is that the utility line would be sponsored by the DoD to link FWA, EAFB, FGA, and GMD. However, it is also possible that the utility line could be constructed by other entities such as a transmission line by GVEA.

Transmission pipelines and electrical transmission lines are similar in that they are both linear type facilities that generally require clearing of a corridor. However, at this point the generalities end, a pipeline is normally constructed in the ground and a transmission line is constructed above the ground. In some cases, depending on local environmental and land use conditions, this can be reversed with pipelines aboveground and transmission lines in-ground. Pipeline corridors are often more narrow than transmission lines, but the impact on the corridor is greater due to trenching and other equipment work areas during construction. However, in operation pipelines often require only minor corridor maintenance. Transmission lines can be constructed with less direct impact on ground surface resources, but maintaining the corridor requires vegetation maintenance for the full width of the corridor. Pipelines are either trenched or directionally drilled under streams, rivers, and lakes, while transmission lines normally span these features or are routed around. For long crossings, both transmission lines and pipelines can be laid on the bottom or trenched in the bottom sediments.

### Regulatory Authority

Since the purpose of the utility line is to provide secure and reliable fuel or electrical power for the military bases and funding for the project would be through the Federal government, the project would be subject to the re-

quirements of NEPA.* NEPA requires an evaluation of the alternatives that are available to meet the needs of the project, and identification of mitigation measures to minimize adverse impacts. The NEPA process is intended to coordinate Federal, state, and local government, and public reviews into a complete and inclusive environmental review process so informed decisions can be made.

Because of the magnitude of the project and the wide range of potential impacts, the proposed action would most likely require the preparation of an EIS. In addition to compliance with NEPA, the project would also require numerous Federal, state and local permits or approvals.

Pipelines and transmission lines would be subject to a wide array of permits depending on the environmental resources impacted and in many cases the same permit may be required for either a pipeline or a transmission line.

### Regulation of Liquid Pipelines and Transmission Lines

Local, state and Federal regulations and ordinances govern all phases of a pipeline's existence including terms of service, routing, design, construction, operations, maintenance, and termination of operations. Additional requirements and recommended practices are governed by national or international technical standards, such as those developed under the American National Standards Institute (ANSI), American Society of Civil Engineers (ASCE) or International Standards Organization (ISO) consensus standard development process.

#### *New Construction*

To construct and operate a pipeline or transmission line, the specific route is proposed based on a number of factors including environmental, land use, construction, access and economics. The opportunity to follow an existing utility easement is another important factor weighed when proposing a new pipeline route. State regulations for route review or approval vary. Some states have legislation or a regulatory process for certifying that the pipeline/transmission line is in the public's interest in the event the applicant has to exercise the right of eminent domain for acquiring a portion of the route. Whatever the state's process of route and project ap-

* See Attachment A for a listing of Federal laws, requirements and orders applicable to the NEPA process.

proval, each project must follow specific local, state, and Federal permitting requirements including (but not limited to):

- Federal environmental permits may be required from agencies such as U.S. Army Corps of Engineers, U.S. Fish and Wildlife, Bureau of Land Management, U.S. Forest Service and others. The number of agencies and specific permits required will vary depending on the route, type of land crossed or ecological resource impacted.*
- State of Alaska environmental permits are required by agencies such as Department of Natural Resources (DNR), ADEC, State Historical Preservation Offices (SHPO), and Department of Fish and Game (DFG). For pipelines, all state land leases are coordinated through the Pipeline Coordinator's Office in DNR.
- The Alaska Joint Pipeline Office (JPO) coordinates the permitting and oversight activities of state and Federal agencies. The JPO was established in 1990, and it includes seven state and six Federal agencies sharing similar regulatory or management responsibilities related to common carrier pipelines. Representatives from nine of the 13 agencies are co-located and coordinate oversight of oil and gas pipelines, and issue right-of-way (ROW) leases and other permits needed for oil and gas projects. Cooperative agreements were developed between agencies to share staff, knowledge, equipment, and office space.
- Local permits for new pipeline or transmission projects may include zoning amendments, conditional use permits, and ROW franchise agreements. Some jurisdictions may also have environmentally sensitive area ordinances.
- In any major project, a wide variety and number of local, state and Federal agencies require numerous permits. For major projects, the planning, permitting and route acquisition process can typically extend over 2 or more years.

*Regulatory Oversight of Pipeline Siting, Construction, and Operation*

The design, construction, operation and maintenance of interstate liquid petroleum transmission pipelines is regulated by the U.S. Department of Transportation, Office of Pipeline Safety (OPS) under the Pipeline Safety Act (49 USC Chapter 601). OPS has issued regulations under 49 CFR Parts 194, 195 and 199. These Federal pipeline safety regulations were promulgated to:

* Note that while the Federal Energy Regulatory Commission (FERC) is the lead agency for permitting of interstate natural gas pipelines, FERC does not have a similar role for liquid pipelines.

- ensure safety in design, construction, inspection, testing, operation, and maintenance of natural gas and hazardous liquid pipeline facilities and in the siting, construction, operation, and maintenance of LNG facilities
- set out parameters for administering the pipeline safety program
- require pipeline operators to implement and maintain anti-drug and alcohol misuse prevention programs for employees who perform safety-sensitive functions
- delineate requirements for onshore oil pipeline response plans.

There may be additional state regulatory requirements. In some cases, states have received approval from the Federal OPS to inspect intrastate pipelines for compliance with Federal pipeline safety regulations, although enforcement authority remains under the jurisdiction of the Federal OPS to assure continuity in interstate commerce. Offshore pipelines are regulated by the Minerals Management Service.

Pipeline safety regulations govern the entire life of pipeline operations, including design, construction, inspection, record-keeping, worker qualification, and emergency preparedness. Other agencies have complimentary regulatory jurisdictional roles related to pipeline safety such as

- *National Transportation Safety Board* for investigation of certain pipeline accidents
- *Occupational Safety and Health Administration* for worker safety and hazardous material emergency response
- *Environmental Protection Agency* (and/or corresponding state environmental agencies) for permitting of emission from tanks and some other facilities and response and remediation of liquid petroleum spills
- *U.S. Coast Guard* relative to preparedness and response to spills in navigable waters
- *State and County Emergency Management Agencies* may have regional emergency planning and notification requirements and, along with local emergency responders, would be involved in oversight of the pipeline.

*Regulatory Oversight of Transmission Line Siting, Construction and Operation*

Unlike pipelines, which are regulated either by the Department of Transportation (OPS) or FERC (interstate natural gas pipelines), the siting, construction and operation of electrical transmission lines does not fall under the direct purview of any one single Federal agency. In addition, in Alaska

there is no one state agency similar to the Pipeline Coordinator's Office or the JPO that coordinates the siting, construction and operation of transmission lines. Nevertheless, construction of transmission lines must comply with NEPA if there is a Federal action and obtain numerous Federal, state and local permits and approvals.

### Utility Line Preliminary Data Gathering

Before initiating the formal regulatory process it is important to gather preliminary information on the proposed action including, alternative routes, land ownership, baseline environmental information, preliminary engineering, and a permitting analysis (agencies with jurisdiction, permits required, and data and information required). The purpose of this initial information and data gathering is to:

- Understand the baseline conditions and what the potential (direct, indirect, and cumulative) impacts are.
- Determine the reasonableness of alternatives and potential insurmountable obstacles. Screening criteria can be used to determine which alternatives should be carried forward in the EIS and which should be eliminated from further consideration.
- Determine what level of effort may be required during the EIS process.
- Identify alternatives and the preferred alternative.
- What steps may have to be taken to avoid or mitigate for significant impacts.

During this preliminary stage, a decision should also be made on which Federal agency will take the lead role in preparing the EIS. Although one Federal agency will take the lead responsibility for ensuring compliance with NEPA, the other Federal agencies with jurisdiction may be cooperating agencies. Early consultation should also be conducted with state and local agencies with regulatory jurisdiction.

One of the most important keys to the NEPA process is data management and recordkeeping. In addition to collecting and managing technical data, it is critical to begin at the earliest possible time to maintain an administrative record of the process.

A listing of environmental permits that may be required for a liquids pipeline are listed in Table 28. The environmental permits that may be required for an electrical transmission line are listed in Table 29.

Table 28. Liquids pipeline Federal, state, and local permits or approvals.

| Federal Agency* | Regulatory Action | Purpose |
|---|---|---|
| NEPA | Lead Agency (To Be Determined) | Comply with NEPA |
| U.S. Army Corps of Engineers | Section 404 Permit | Discharge of dredged or fill material |
| | Section 10 Permit | Work in navigable waterway |
| U.S. Army Alaska | Letter of Non-Objection | Army serves as the trustee of public dominion lands withdrawn for military purposes. Army must sign a letter of non-objection before a ROW permit across Army lands can be issued. |
| EPA | Stormwater National Pollutant Discharge Elimination System (NPDES) Permits | Prevent soil erosion and water quality degradation |
| | Spill Prevention Control and Contingency Plans | Spill prevention in the event of a spill along the pipeline |
| | Permit to handle Hazardous Waste | Permit to handle hazardous waste–quantity dependent |
| Federal Communications Commission | Radio/Wireless Communication Permits and Licenses | Remote sensing devices may use wireless data transmission |
| Bureau of Land Management (BLM) | Plan of Operation | Plan describing how the project will be constructed and emergency contingency plans |
| | Material Sales | Sale of resources of off Federal land–timber from clearing operations |
| Advisory Council on Historic Preservation (ACHP) | Section 106 Review–Cultural Resource Review | Protection for historic and archaeological sites potentially impacted by Federal permitted or licensed project. |
| Dept. of Defense, Bureau of Indian Affairs, others | Land Use Authorizations | Approval to cross Federal jurisdictional lands |
| U.S. Fish & Wildlife Service | Biological Assessment/Section 7 Consultation | A Section 7 consultation is required to assure protection of endangered or threatened species and wildlife. |
| U.S. Coast Guard | Bridge Permits | Crossing over a bridge with the pipeline |
| State Agency | Regulatory Action | Purpose |
| Regulatory Commission of Alaska (intrastate) | Certificate of Public Convenience and Necessity | A public utility or pipeline carrier must obtain a certificate of public convenience and necessity, if providing gas to customers |
| DNR | ROW Lease | Crossing of land managed by DNR |
| | Water Appropriations | Water for use in pipeline hydrostatic testing |
| | 906(k) Concurrence | Required for ROW requests across state selected lands. |
| | Material Sales | Sale of material from DNR land–timber from clearing |

* This listing is primarily focused on environmental permits and is not intended to be inclusive of all permits and authorizations that may be needed for the construction and operation of a pipeline.

| Federal Agency* | Regulatory Action | Purpose |
|---|---|---|
| | Burning and Air Quality Permits | Approval to burn debris during construction |
| Various State Agencies | Land Use Authorizations | Crossing of any lands owned or managed by state agency require an authorization |
| ADEC | 401 Water Quality Certification | Required prior to issuance of a Federal permit or authorization that could impact water quality |
| | Waste Discharge Permit | Required if hydrostatic test waters are discharged in waters of the state |
| | Oil Discharge Contingency Plans | Oil spill contingency plans |
| | Solid Waste Disposal Permits | If a new solid waste site is created a permit is required |
| | Air Quality Permits | Air permits may be required for pumping stations if diesel operated–burning of debris |
| DFG | Habitat Protection Permits | If the project impacts sensitive habitats or streams, rivers, or lakes a permit is required |
| Alaska Department of Transportation and Public Facilities (ADOT&PF) | Utility Permits | If the proposed pipeline encroaches on a state highway easement a permit is required |
| Department of Government Coordination (DGC) | Alaska Coastal Management Program Consistency | Required if the project is in the coastal zone. |
| Borough/Municipal | Notice of Intent | Local jurisdictions may require the filing of a notice of Intent or Actions if the project is within jurisdictional boundaries |
| Borough/Municipal | Zoning Requirements and Land Use Permits | Pipeline is compatible with designated land use and zoning |
| Borough/Municipal | Conditional Use Permits | Conditional Use Permit to ensure consistency with borough ordinances |
| Borough/Municipal | ROW/Franchise Permit | ROW permits or franchise agreements for utility crossings of lands or use of rights-of-ways. |
| Borough | Floodplain Permit | Approval for construction in floodplains. |
| Native and private lands | Leases, Rights-of-Way, Land Use Authorizations | Authorizations and leases are required to cross Native and private lands |

**Table 29. Transmission line Federal, state, and local permits and approvals.**

| Federal Agencies | Regulatory Action | Purpose |
|---|---|---|
| To be Determined | EIS | Potential lead agency for NEPA. |
| BLM | ROW Permit | A ROW permit will be required for any portions of the route which cross Federal lands. Includes military lands, state selected lands under the statehood act, native selected lands under Alaska Native Claims Settlement Act, and non-certificated Native allotments under the Alaska Native Allotment Act of 1906. |

| Federal Agencies | Regulatory Action | Purpose |
|---|---|---|
| U.S. Army Alaska | Letter of Non-Objection | Army serves as the trustee of public dominion lands withdrawn for military purposes. Army must sign a letter of non-objection before a ROW permit across Army lands can be issued. |
| U.S. Army Corps of Engineers | Section 10 Permit | Section 10 permit is required for construction or placement of structures in or above navigable waters of the United States. |
| | Section 404 Permit | Section 404 Permit is required for the discharge of dredged or fill material into U.S. waters including wetlands. |
| Rural Utilities Service | Approval of financial assistance / NEPA compliance | If the project funding is provided to a local utility to construct the project through RUS or assistance with obtaining financing requires compliance with NEPA. RUS would be a potential lead agency or cooperating agency. |
| U.S. Fish & Wildlife Service | Biological Assessment/Section 7 Consultation | A Section 7 consultation is required to assure protection of endangered or threatened species and wildlife. |
| | Threatened or endangered species Take Permit | A permit is required for an action that has the potential to result in the taking of a threatened or endangered species |
| ACHP | Section 106 Review—Cultural Resource Review | Protection for historic and archaeological sites potentially impacted by Federal permitted or licensed project. |
| Federal Aviation Administration (FAA) | Notice of Proposed Construction or Alteration | A notice to the FAA, for review and approval, required if any structure enters the airspace within a 100:1 slope of any runway. |
| EPA | EIS Review | Under Section 309 of the Clean Air Act, the EPA is given the authority to review and comment on the environmental impact of a proposed action. |
| | National Pollutant Discharge Elimination System | Permit required for discharge of wastewater from a point source waters of the U.S. The Permit is also required for storm water runoff, administered by the state. |
| | Spill Prevention Control and Countermeasure Plans | Plans are required for above and below ground oil storage facilities meeting capacity criteria |
| State Permits | Regulatory Action | Purpose |
| ADEC | 401 Water Quality Certificate | A 401 Certificate to be issued for any Federal action or permit that may impact water quality |
| | Air Quality Control Permit | Authorization of plans and specifications for construction that results in potential impacts to air quality including road dust, wind-blown contaminants, and emissions from generators. |
| | Solid Waste Disposal Permits | If a new solid waste site is created for disposal of debris a permit is required |
| | Surface Oiling Permit | Control of road dust. To control and legalize surface oiling—to prevent water pollution. |
| DNR | Material Sale | A material sale is required for the use of state materials along the proposed ROW (i.e., gravel, timber). |

| Federal Agencies | Regulatory Action | Purpose |
|---|---|---|
| | Land Use Permit | A land use permit is required for use of state lands for the proposed ROW. |
| | 906(k) Concurrence | Required for ROW requests across state selected lands. |
| | ROW Permit | A ROW is required for construction of transmission lines or other improvements that cross state lands. |
| DFG | Fish Habitat Permit (Title 16 Permit) | A General Waterway/Waterbody Application must be submitted construction activities disturb the natural flow or bed of any stream, river, or lake. |
| | Approval for Equipment Ford of State Waters | An Application for a Equipment Ford must be obtained to move equipment across State waters |
| ADOT&PF | Utility Permit | Required before construction on managed state lands including structures crossing ADOT&PF ROWs. |
| Local Agencies | Regulatory Action | Purpose |
| Borough/Municipal | Notice of Intent | Local jurisdictions may require the filing of a notice of Intent or Actions if the project is within jurisdictional boundaries |
| Borough/Municipal | Zoning and Land Use | Transmission line is allowable in the land use zone |
| Borough/Municipal | Conditional Use Permit (CUP) | A CUP may be required for transmission line and/or substation in certain zoning districts. |
| Borough | Floodplain Permit | Approval for construction in floodplains. |
| Borough/Municipal | ROW/Franchise Permit | ROW permits or franchise agreements for utility crossings of lands or use of rights-of-ways. |
| Native and private lands | Leases, Rights-of-Way, Land Use Authorizations | Authorizations and leases are required to cross Native and private lands |

# 11 Evaluation Criteria

For evaluating technologies for further consideration, the technology needed to be proven, viable, and practical. The technology or concept also needed to meet other evaluation criteria in terms of its ability to meet long-term needs, community requirements, energy security, and environmental regulations.

After the technologies were determined, they were evaluated using the criteria of security, life cycle costs, capital cost, air and water quality, cost stability, impact on Alaska infrastructure, water and solid waste reduction, and operating cost.

## Technology Evaluation

For a technology to be considered, it needed to be proven, viable, and practical.

### Proven Technology

The technology must have reached sufficient maturity that it can be regarded as proven. Technologies at the research or demonstration stage are not considered proven.

### Viable

The technology must be viable in the sense that it will be able to provide reliable, competitively priced heat or power for a period of 25 years or more. The technology must also be able to be permitted and operated under current requirements.

### Practical

The technology must be practical and able to operate in the Interior Alaska environment and harsh climate. Operation of the technology cannot require a level of sophistication that is not typically available in the Fairbanks area.

Additional criteria used for evaluation are discussed below.

### Ability To Meet Long-Term Needs, Community Requirements, and Energy Security

If a technology or alternative cannot meet long-term needs, would not be acceptable to the community (e.g., nuclear), could not support community requirements, and was not secure, the technology or alternative was not evaluated.

### Adaptability to Natural Gas

If an alternative precluded the ability to use natural gas in the future, the alternative was not evaluated. Evaluated alternatives either included the ability to use natural gas as a fuel or did not preclude another alternative that uses natural gas.

### Applicable Environmental Regulations and Statutes

For evaluation purposes, if a technology or alternative is not able to meet the applicable environmental regulations and statutes, it was not deemed a viable alternative.

### Air and Water Quality

If a technology or alternative could meet air quality and water quality constraints, further evaluation based on air or water quality issues is not a significant discriminator and, therefore, this criteria was considered a threshold requirement.

Our environmental review has not indicated any air quality issues to suggest that new boiler and/or CT–based generation cannot be permitted.

Water is available in adequate amounts, whether for coal-fired boilers or for CTs.

### Competitively Priced Heat and Power

If a technology or alternative clearly is not economically competitive with other alternatives for providing heat and power, it was not considered further.

### Implementation Schedule

There is sufficient heat generation capability at the existing installations to meet needs for the next 25 years. There also is the ability to purchase electricity from GVEA. As a result, the relative advantage of a technology or alternative that can be implemented quickly is not a meaningful discriminator unless the technology or alternative has an exceptionally long lead-time. This criterion was not used.

### Performance Risk

Performance risk reflects technology maturity; immature or noncommercial technologies are not considered further.

### Reliability

This criterion favors proven technology, redundancy, and flexibility. Alternatives need to provide sufficient reserve capacity and redundancy to allow the largest single unit (boiler, generator) to be out of service and still be able to meet peak load requirements. All alternatives were developed to provide reliability comparable to what the installations have now.

### Water and Solid Waste Reduction

Our discussions with interested parties did not identify any significant constraints or issues associated with the use of water at the facilities. The solid waste associated with the FWA and EAFB CHPPs is ash, and we did not find evidence that ash disposal is a significant issue or constraint.

## Evaluation Criteria

After applying the above requirements to various technologies, alternatives were developed to meet the projected steam heating and electricity loads. The alternatives included capacity and redundancy to provide reliability and performance consistent with existing requirements.

### Evaluation of Fuels

Fuels (coal, oil, natural gas, etc.) were evaluated separately from specific alternatives because the issues involving fuel choices are different than specific alternative choices.

*Fuel-Related Evaluation Criteria*

The following criteria were used to evaluate fuels:

<u>Availability/Reliability</u>

Is the fuel available in appropriate quantities during the study period and is the supply reliable? This criterion was given a weight of 40 percent.

<u>Fuel Security</u>

Is the fuel supply secure from disruption? This criterion was given a weight of 20 percent.

<u>Price Volatility/Cost Stability</u>

Does the fuel choice contribute to a diversity of choice and provide the ability to shift from one fuel to another if prices become volatile or very high? This criterion was given a weight of 20 percent.

<u>Environmental Issues</u>

Are there significant environmental issues associated with the fuel? This criterion was given a weight of 10 percent.

<u>Waste Reduction</u>

Are there significant waste issues associated with the fuel? This criterion was given a weight of 10 percent.

### Fuels Evaluation

Based on the above criteria and the discussion in Chapter 3, "Fuels in Interior Alaska" (p 30), coal, fuel oil and natural gas were evaluated as the data in Table 30 and Figure 16 indicate. It can be seen that coal was evaluated as providing the highest degree of Availability/Reliability, Security and Price Volatility/Cost Stability. It was scored the lowest on Environment and Waste Reduction.

Oil was scored somewhat lower than coal on Availability/Reliability because of the declining output of the North Slope oil fields, lower on Security because the TAPS is a single source of supply and because of the need for the North Pole refineries to refine the product, and relatively low on Price Volatility/Cost Stability. It was scored high for Environmental considerations and Waste Reduction. Oil distillates received the same scores.

Table 30. Fuels evaluation, fuels and fuel delivery evaluation matrix.

| Criteria | Weighting | Raw Score | | | | | |
|---|---|---|---|---|---|---|---|
| | | Single Fuel | | | | Dual Fuel | |
| | | Coal | Oil | Naphtha, JP-8, DFA | Nat. Gas | Coal-Oil, JP-8, DFA | Coal-Nat. Gas |
| Availability/Reliability | 40% | 10.00 | 7.00 | 7.00 | 7.00 | 10.00 | 10.00 |
| Security | 20% | 10.00 | 6.00 | 6.00 | 6.00 | 10.00 | 10.00 |
| Price Volatility/Cost Stability | 20% | 10.00 | 3.00 | 3.00 | 3.00 | 10.00 | 10.00 |
| Environmental | 10% | 2.00 | 9.00 | 9.00 | 10.00 | 2.00 | 4.00 |
| Waste Reduction | 10% | 2.00 | 10.00 | 10.00 | 10.00 | 2.00 | 2.00 |
| Total | 100% | 34.00 | 35.00 | 35.00 | 36.00 | 34.00 | 36.00 |
| Weighted | | 8.40 | 6.50 | 6.50 | 6.60 | 8.40 | 8.60 |
| Indexed to Maximum Score | | 0.98 | 0.76 | 0.76 | 0.77 | 0.98 | 1.00 |
| Scoring: A score of 10 is the highest; a score of 1 is the lowest. Explanation of scoring is provided separately. | | | | | | | |

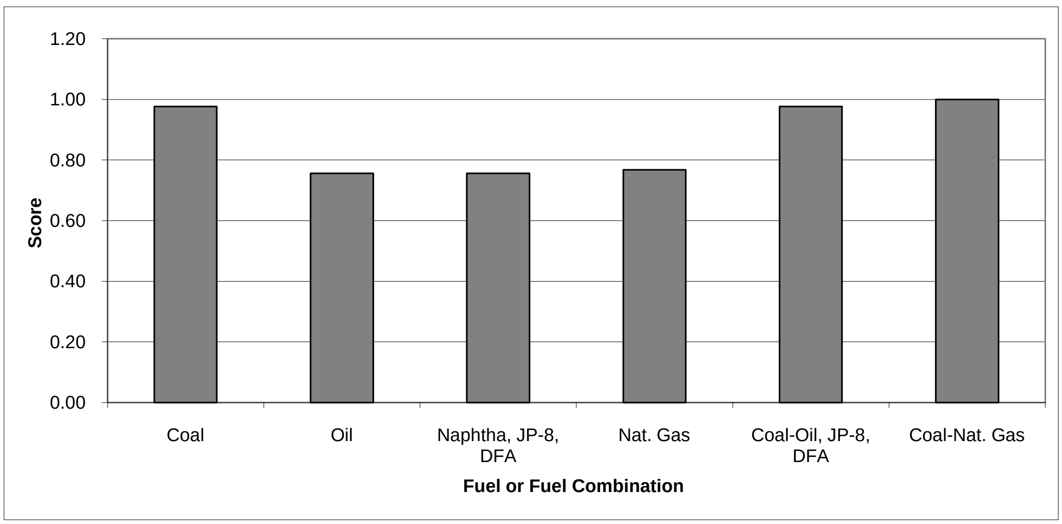



Figure 16. Evaluation of fuels (normalized to a maximum score of 1).

Natural gas was scored the same as oil for Availability/Reliability based on the two recent pipeline applications discussed. This might be somewhat optimistic given the uncertain schedule for the pipeline being in service. It was also scored the same as oil for Security and Price Volatility/Cost Stability. It was scored at the maximum for Environmental and Waste Reduction.

For dual fuel capability, the coal-fuel oil combination was scored based on coal. The coal-natural gas combination was scored on the basis of coal, with the exception for Environmental which was scored somewhat higher for Environmental. This resulted in the coal-natural gas combination receiving the highest overall score, 1.00, and the coal only fuel receiving a score of 0.98.

### Evaluation Criteria for Alternatives

The evaluation criteria used for individual alternatives were:

- security (40 percent)
- life cycle cost (30 percent)
- capital cost (7 percent)
- air and water quality (5 percent)
- cost stability (5 percent)
- impact on Alaska infrastructure (5 percent)
- water and solid waste reduction (5 percent)
- operating cost (3 percent).

The specific alternatives were evaluated on the basis of these criteria, as discussed below. The scoring range for each criterion is 1 (low) to 10 (high).

#### *Energy Surety*

Energy Surety (elsewhere in this report, the term "security" is used to represent the same criteria) is defined as providing energy when and where needed, in the right amount, at a competitive price. It is a guarantee of system performance. Surety is the right combination of reliability, security, safety and sustainability for optimal system performance. The meanings of these words are often intertwined and far from distinct. The following definitions of terms comprising surety are used for evaluation and decision-making. The following definitions of these terms are meant to reduce the possibility of double counting these individual parameters.

#### *Reliability*

System performance based on system configuration, quality of components and level of backup components. It is also based on the ability to perform after "non-human" events such as "acts of God."

#### *Security*

System performance based on human related vulnerabilities (such as sabotage, error, negligence, and vandalism).

*Safety*

System performance design margin, the sizing of components from theoretical design criteria that may be either positive or negative and result in a safety factor (over design) or in a capacity limitation (under design).

*Sustainability*

System performance resulting from a persistent availability of fuel, affordable pricing, diversity or adaptability of fueling options, and environmentally friendly clean operation.

The overall criterion of energy surety (or security) was given a weighting of 40 percent, which is the highest weighting among the alternatives evaluation criteria.

*Life-Cycle Costs*

Life-cycle costs, the net present value of the cost stream for the study period, are major evaluation criteria. The life-cycle cost reflects both the capital cost of the alternative and the annual cost of operation and maintenance. The lowest life-cycle cost received a score of 10. Each other alternative received a lower score based on the life-cycle cost relative to the lowest life-cycle cost. This criterion was given a weighting of 30 percent.

*Capital Cost*

This criterion is used to reflect additional weighting of the relative capital costs of the alternatives. Alternatives with lower front-end capital cost, such as CTs using oil or natural gas, would be scored higher than coal-fired alternatives that are more capital intensive. The lowest capital cost alternative received a score of 10. The other alternatives were ranked lower based on their capital cost. This criterion was given a weighting of 7 percent.

*Air and Water Quality*

Air and water quality are important evaluation criteria. Environmental regulation can be expected to become more stringent over time. To the extent an alternative has fewer emissions and water quality impacts, it receives a higher score. Alternatives with higher emissions and water quality impacts received lower scores. This criterion was given a weighting of 5 percent.

*Cost Stability*

This criterion recognizes the exposure of the alternative to increases in costs, whether because of fuel cost exposure or operating cost exposure. The alternative with the least exposure to significantly increased costs of fuel or operation received a 10. Alternatives with greater exposure received lower scores. This criterion was given a weighting of 5 percent.

*Impact on Alaska Infrastructure*

This criterion reflects the use of additional resources (negative impact) or reflects a reinforcement of the existing energy supply infrastructure in Interior Alaska. For evaluation purposes, each alternative was ranked according to its contribution toward Interior Alaska infrastructure (electric transmission, fuel supply, fuel alternatives, etc.). The alternative contributing the most to the infrastructure received a score of 10. The other alternatives received a lesser score based on a qualitative evaluation. This criterion was given a weighting of 5 percent.

*Water and Solid Waste Reduction*

Alternatives that placed the least burden on existing water resources and solid waste management programs received a maximum score of 10; alternatives with the greatest demand on these resources received lower scores. This criterion was given a weighting of 5 percent.

*Operating Cost*

The same comments apply to operating cost as to capital cost. This criterion was given a weighting of 3 percent.

The technologies reviewed and the alternatives evaluated are discussed in more detail in the following Chapters.

# 12 Technologies and Concepts Evaluation

Before developing alternatives for further evaluation, a number of technologies or approaches were reviewed. For a technology to merit further evaluation, the technology must be proven, viable, and practical. For an approach to merit further evaluation, it must provide a cost-effective solution. The evaluation process reviewed a range of technologies and approaches that might have merit for further consideration and if the review could not establish that the technology or approach met the threshold criteria of proven, viable and practical, it was not considered further.

Technologies that were determined to not meet the requirements for further evaluation are discussed below. At some point in the future, some of these technologies may become proven, viable and practical and should be considered at that time.

Appendix B includes additional materials on the various technologies.

## Technologies

### Nuclear Power

Nuclear power, at the scale appropriate for the GFMC or Interior Alaska, does not meet the above criteria. Historically, nuclear power was cost effective at very large scale (1,000 MW); smaller installations were not cost effective. There have been recent proposals for much smaller-scale installations, on the order of 10 to 100 MW.

Any given design must receive approval from the United States Nuclear Regulatory Commission before it can be considered viable. Our review did not identify any designs at the 10 to 50 MW scale that have such approval. There was a recent proposal by Toshiba Corporation to develop, design, and construct a 10-MW installation for the community of Galena, AK. A newspaper article on the proposal included the following:

> Department of Energy officials say the new technology is promising, but enormous hurdles remain. A reactor of this type and size has never been built anywhere in the world, much less tested and licensed for use in the United States. The cost of building a prototype that meets stringent U.S. safety standards could kill it, said a nuclear engineer at the Energy Department's Lawrence Livermore National Laboratory in California.

> Public skepticism is another potential barrier. The proposed plant would be the first commercial use of nuclear power in Alaska, but fears about potential accidents and about disposal of nuclear waste have chilled the industry in the Lower 48. No new commercial plants have been licensed since the late 1980s.
>
> 'The biggest hurdle is winning approval by the U.S. Nuclear Regulatory Commission,' he said, 'which will require Toshiba to finish its design, then build a prototype.' He estimated the work would cost $600 million or more and take six to eight years. 'The Galena plant could be online by 2010,' he said. 'Once the first one is complete, Toshiba believes it can build additional plants for about $20 million each,' he said.
>
> 'The real problem ... is public acceptance.' Stevens said.
>
> '... the Air Force had to remove 10 small generators powered by a radioactive source in the northeastern Interior in 2001 after the nearest villagers learned about the material and complained.'

An installation such as the one described does not represent a reasonable long-term power supply option for the GFMC until such time as it is proven and community acceptance is likely.

### U.S. Department of Energy (DOE) Clean Coal Demonstration Projects

DOE efforts to develop long-term clean coal and other technologies are an important effort to make coal a more environmentally friendly fuel. To the extent the DOE program demonstrates and proves technologies that move into the commercial market place, the technologies have application for the GFMC. A case in point is circulating fluidized-bed combustion boilers.

To the extent the programs are in the development stage and have not moved into commercial application, they do not meet the criteria of proven, viable, and practical.

The DOE *FutureGen* Tomorrow's Pollution-Free Power Plant and *Vision 21*—The "Ultimate" Power Plant programs are prototypes and not considered proven.

They involve coal gasification, advanced gas turbines, fuel cells, and the sequestration of carbon. Coal gasification is a technology that can lead to significant emissions reductions. However, it also involves an energy pe-

nalty because of the need to clean the hot gas. Hot gas clean up is an emerging technology that is not yet proven or practical.

Our research indicates that most traditional power providers do not have the chemical process experience to successfully operate coal gasification facilities. If and when coal gasification becomes a proven, viable, economically competitive option, it can be considered for future generation in Alaska. At the current time, it does not meet the threshold criteria.

The DOE *Clean Coal Power Initiative* and *Clear Skies Initiative* programs include a number of efforts to demonstrate technology for the reduction of emissions from power plants. The efforts include: greenhouse gas reductions, $SO_2$ emission reductions, NOx emissions, mercury emissions, particulates at the $PM_{2.5}$ level, recycling of carbon and other power plant waste products, and reuse of power plant cooling and other process water. These programs are intended to demonstrate technologies that can be commercially applied to the use of coal as a fuel.

For a study such as this one, it is inappropriate to identify a specific technology that might be applied to a coal-fired power plant unless that technology has achieved relatively wide spread acceptance and application in the industry. The important consideration is to recognize the need for environmental controls and to recognize the cost impacts of compliance with those requirements. Specific technology selection would be done at the project pre-design and design levels.

### North Slope Power Plant and Transmission to the Railbelt Area

The possible development of natural-gas fired power plants on the North Slope would require high voltage transmission lines to move the power to Fairbanks for interconnection to the Railbelt Intertie.

The cost of the transmission would be prohibitive. At an estimated cost of $1 million a mile or more, the line would cost $350 million or more. The Railbelt electrical loads do not justify this amount of transmission line investment. If this type of solution to Alaska power supply needs were undertaken, it would require the involvement of the State and all of the Railbelt electric utilities. It would also result in the utilities being dependent on the transmission line(s) for firm power, which would require that they maintain backup generation locally.

The proposed development of a North Slope natural gas pipeline may bring natural gas to Fairbanks, at which time local generation could be developed at a much lower cost. The North Slope natural gas might also be converted to LNG and brought into the Fairbanks area.

### "Green" Renewable Technologies

The available "green" resources and renewable resources in the interior of Alaska are wind and solar. Geothermal, hydroelectric, biomass, and municipal solid waste resources are either not present or are present in amounts that are too limited to support development.

Wind and solar are available, but do not provide firm power supply that can be relied on to meet installation needs, particularly during harsh wintertime conditions. They do provide for fuel displacement when they are available. Table 31 lists data indicating how renewables might be applied in Interior Alaska.

#### *Solar*

Solar technologies (e.g., photovoltaic systems) are not practical for meeting substantial portions of installation electrical requirements due to limited resources (sunshine) during the winter. For example, a 100 kW photovoltaic (PV) array would provide about 113,608 kWh/year or 13 average kW of power, a 13 percent capacity factor. Table 32 lists the energy output of a 100kW PV array.

Assuming the installation is interconnected to the GVEA system, batteries would not be required. Typical installed costs of grid-connected photovoltaic systems are on the order $10,000/kW, or about $1 million for a 100 kW system. Photovoltaic system efficiencies are about 10 to 13 percent (sunlight to electricity). The key advantages of PV are low operation and maintenance costs due to "free" fuel and few moving parts or components requiring service. Since no fuel is needed, photovoltaic systems can serve as a hedge against fuel price variability.

Table 33 lists the number of 100-kW arrays needed to provide 10 or 20 percent of FWA's annual electricity needs. The analysis found that 90 100-kW arrays would be needed to provide 10 percent of the needs and would require a solar panel area of 21 acres. This system would cost at least $90 million. The annual cost per kWh produced is estimated at more than $1 per kWh. To meet a 20 percent goal would require 170 arrays and about 40 acres, at the same cost per kWh.

Table 31. Summary of renewables in interior Alaska.

| Resource | Best Applicability of Resource (Time of Year) | | | |
|---|---|---|---|---|
| | FWA | EAFB | FGA/GMD | Comment |
| Solar | March–September | March–September | March–September | During peak month of April, the capacity factor is 24 percent. Minimal amount October–February. |
| Wind | None | None | Year-round | GVEA is investigating 10 to 20 MW of wind resource development. Looking at both the Greely and the Healy areas. |
| Geothermal | None | None | None | Nearest resource is Chena Hot Springs, 50 miles away |
| Fuel Cells | Year-round | Year-round | Year-round | Fuel (natural gas) must be clean, and available on site. Too small a scale to represent a solution. |
| Hydro | None | None | None | |
| Municipal Solid Waste (MSW) | Not enough volume | Not enough volume | Not enough volume | Will require burning coal to supplement MSW |
| Biomass | Not enough volume | Not enough volume | Not enough volume | Will require burning coal to supplement MSW |

Table 32. Energy Output of a 100-kW Photovoltaic Array at FWA.

| Month | Energy Output (kWh) |
|---|---|
| January | 2,377 |
| February | 7,033 |
| March | 14,312 |
| April | 17,263 |
| May | 14,128 |
| June | 13,260 |
| July | 13,264 |
| August | 11,653 |
| September | 9,200 |
| October | 6,535 |
| November | 3,393 |
| December | 1,191 |
| Annual | 113,608 |
| Source: PVWatts Version 1, Fairbanks, AK, solar data for a 100-kW array (http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/) | |

Table 33. Solar power arrays for Fort Wainwright to meet 10 and 20 percent renewable energy requirement using May 2001 to April 2002 loads.

| Month | Fort Wainwright MWh | kWh | 10% of kWh | 20% of kWh | Energy Output 100-kW PV Array (kWh) | No. of Arrays To Meet 10% kWh | To Meet 20% kWh | No. of Arrays 90 (kWh) | 170 (kWh) |
|---|---|---|---|---|---|---|---|---|---|
| January | 10,109.2 | 10,109,200 | 1,010,920 | 2,021,840 | 2,377.0 | 425.3 | 850.6 | 213,930 | 404,090 |
| February | 9,195.5 | 9,195,500 | 919,550 | 1,839,100 | 7,033.0 | 130.7 | 261.5 | 632,970 | 1,195,610 |
| March | 9,453.9 | 9,453,900 | 945,390 | 1,890,780 | 14,312.0 | 66.1 | 132.1 | 1,288,080 | 2,433,040 |
| April | 7,660.3 | 7,660,300 | 766,030 | 1,532,060 | 17,263.0 | 44.4 | 88.7 | 1,553,670 | 2,934,710 |
| May | 7,833.5 | 7,833,500 | 783,350 | 1,566,700 | 14,128.0 | 55.4 | 110.9 | 1,271,520 | 2,401,760 |
| June | 6,300.0 | 6,300,000 | 630,000 | 1,260,000 | 13,260.0 | 47.5 | 95.0 | 1,193,400 | 2,254,200 |
| July | 5,737.1 | 5,737,100 | 573,710 | 1,147,420 | 13,264.0 | 43.3 | 86.5 | 1,193,760 | 2,254,880 |
| August | 5,894.0 | 5,894,000 | 589,400 | 1,178,800 | 11,653.0 | 50.6 | 101.2 | 1,048,770 | 1,981,010 |
| September | 5,981.4 | 5,981,400 | 598,140 | 1,196,280 | 9,200.0 | 65.0 | 130.0 | 828,000 | 1,564,000 |
| October | 8,181.2 | 8,181,200 | 818,120 | 1,636,240 | 6,535.0 | 125.2 | 250.4 | 588,150 | 1,110,950 |
| November | 8,923.5 | 8,923,500 | 892,350 | 1,784,700 | 3,393.0 | 263.0 | 526.0 | 305,370 | 576,810 |
| December | 9,368.1 | 9,368,100 | 936,810 | 1,873,620 | 1,191.0 | 786.6 | 1,573.1 | 107,190 | 202,470 |
| Annual | 94,637.7 | 94,637,700 | 9,463,770 | 18,927,540 | 113,609.0 | — | — | 10,224,810 | 19,313,530 |

***Therefore, total number of 100 kW arrays needed are:*** ***90 to meet 10% of energy*** ***10.8% % of total energy***
***170 to meet 20% of energy*** ***20.4% % of total energy***

| | | | | |
|---|---|---|---|---|
| Capital Cost | $1,500,000 per array (incl. installation) | $135,000,000 | total capital cost to meet 10% of energy | |
| | | $255,000,000 | total capital cost to meet 20% of energy | |
| | $1,000 annual O&M per array | $90,000 | total O & M to meet 10% of energy | |
| | | $170,000 | total O & M to meet 20% of energy | |
| | 10,000 area needed per array (ft$^2$) | 900,000 | ft$^2$ to meet 10% of energy | 20.6 acres |
| | | 1,700,000 | ft$^2$ to meet 20% of energy | 39 acres |

| **Approximate Annual Costs** | **90 Arrays** | **170 Arrays** |
|---|---|---|
| Capital Recovery | $13,500,000 | $25,500,000 |
| Operation & Maintenance | $90,000 | $170,000 |
| Total Annual Cost | $13,590,000 | $25,670,000 |
| Annual Cost per kWh | $1.3291 | $1.3291 |

Figure 17 compares the monthly pattern of solar power energy production with FWA electrical loads. It can be seen that when electrical loads are at their highest, solar energy production is at its lowest. This requires other generation resources to be in place to meet winter-time loads.

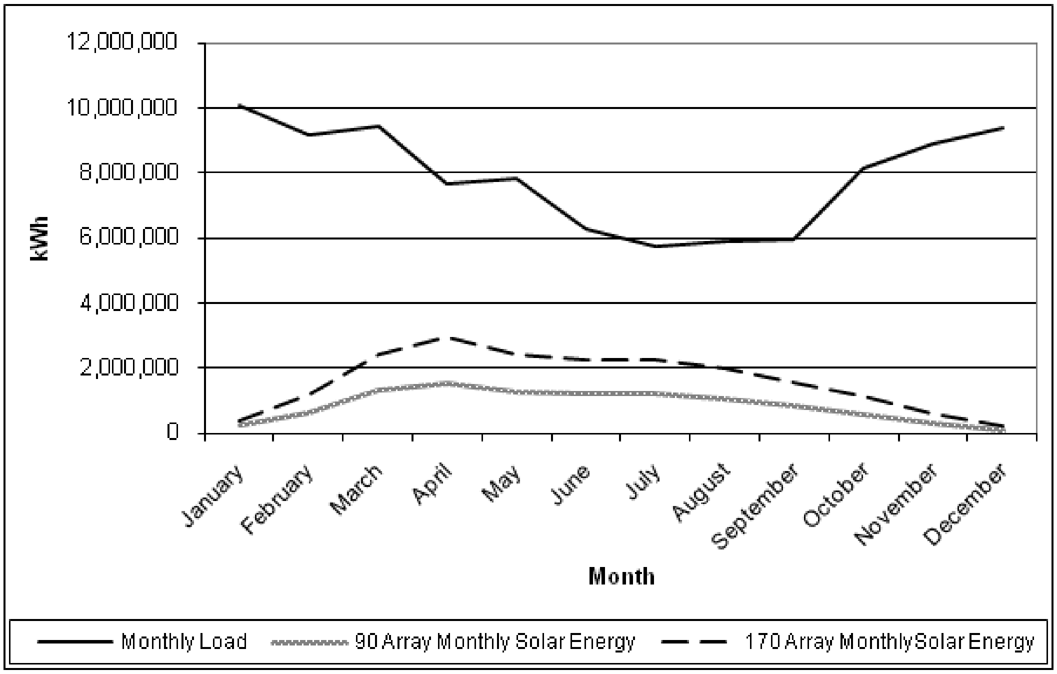



Figure 17. Solar power for FWA.

*Wind*

The Alaska locations that are most desirable for wind power generation are the Aleutian Islands, islands in the Bering Sea, as well as the northern and western coastal areas. The potential for wind generation is based on seven wind power classes, with Class 1 being the lowest and Class 7 the highest. Table 34 lists the wind power classes. The application of large-scale wind turbines typically requires a location to have Class 4 or higher winds to be technically and economically feasible.

Table 34. Wind Power Classes (Source: www.eren.doe.gov).

| Wind Power Class | Avg. Speed (mph) | Wind Power (watts/meter2) |
|---|---|---|
| 1 | 12.5 | 200 |
| 2 | 14.3 | 300 |
| 3 | 15.7 | 400 |
| 4 | 16.8 | 500 |
| 5 | 17.9 | 600 |
| 6 | 19.7 | 800 |

Figures 18 and 19 show wind maps for northern and southern Alaska, respectively. The maps indicate that in the immediate vicinity of Fairbanks, wind power is classified as Class 1. However, there are potential sites for wind generation between Delta Junction and the Alaska Range where Class 4 through Class 7 winds have been identified. This is near FGA and GMD.

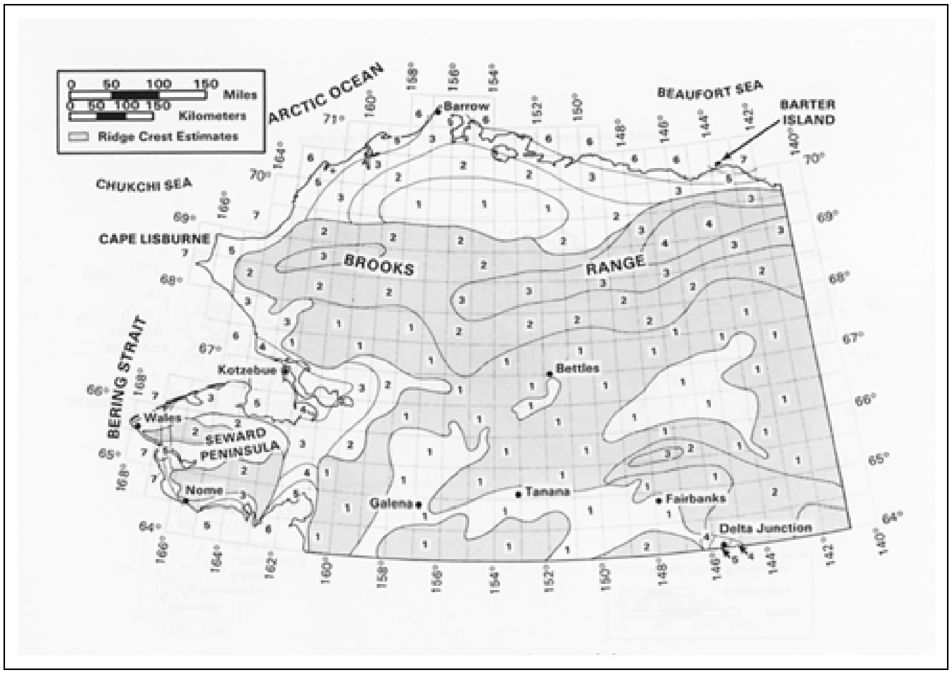



Figure 18. Wind Maps of the Fairbanks Region (Source: http://rredc.nrel.gov).

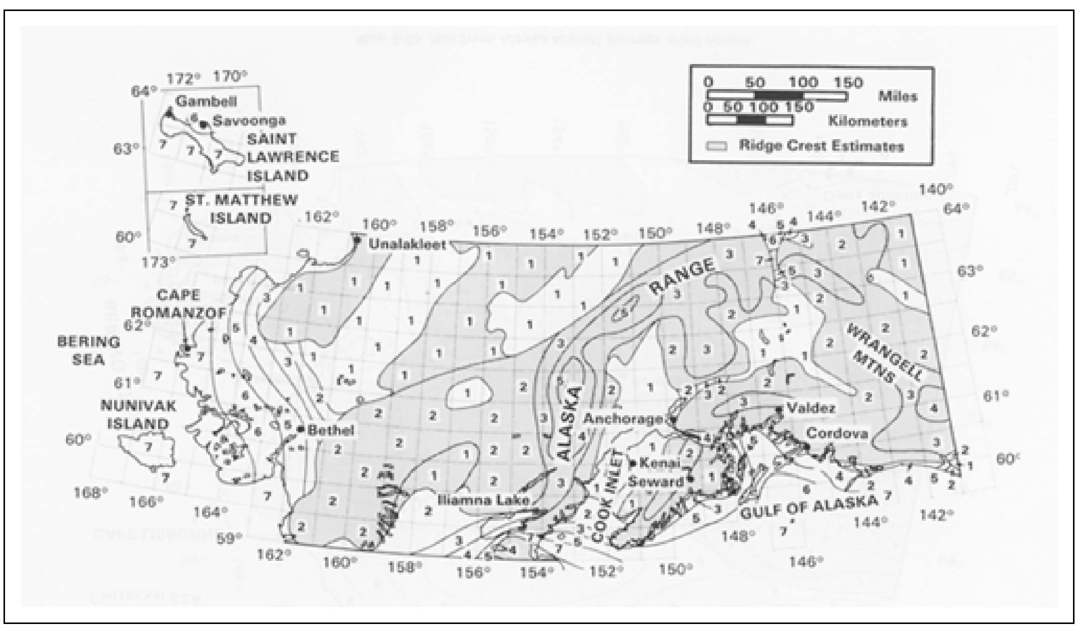



Figure 19. Wind maps of the anchorage region (source: http://rredc.nrel.gov).

Kotzebue Electric Association (KEA) has ten 66-kW wind turbines in service. Kotzebue is located in northwest Alaska on the coast (cf. Figure 18). Three of the turbines went into service in 1997 and 7 in 1999. Average wind speeds in Kotzebue are 13.5 miles per hour. For KEA, the wind generation displaces the use of diesel to generate electricity. The ten turbines produce about 1.2 million kWh annually, which is about a 20 percent capacity factor. KEA also installed a 100 kW turbine in 2000 to demonstrate the use of a different manufacturer's equipment. KEA's peak demands are about 11 MW. It is isolated from other electric systems and is dependent on imported diesel fuel for power generation. To our knowledge, this is the only currently operating electric utility development of wind power in Alaska.

GVEA installed a 10 kW demonstration wind turbine near Healy that operated from May 1998 to April 2000. The turbine required a minimum wind speed of 8 mph to generate electricity. The system was installed at a total cost of $47,400. Results of the demonstration were an availability of 76.8 percent and an average capacity factor of 15.6 percent or 1.56 average kW (source: www.gvea.com).

GVEA is pursuing the development of 10 to 20 MW of wind power in the Healy and Delta Junction areas. This effort is expected to take place over the next several years and includes the gathering of wind speed data, site selection and then development. This effort is an excellent opportunity for the GFMC to support the development of renewable resources in Alaska and to potentially meet the goals of Executive Order 12856.

Similar to the solar power analysis for Fort Wainwright, Table 35 lists the number of wind power turbines needed to meet 10 and 20 percent wind power targets for Fort Wainwright's electricity consumption. Of necessity, the analysis made a number of simplifying assumptions, which might or might not prove entirely valid if a more detailed assessment of the Delta area wind resource were made. Using 1,500 kW wind turbines, which stand 250 to 300 ft high, and the average monthly wind speeds for the Delta Junction airport, it was determined that 3 turbines would be needed to meet the 10 percent goal. Five would be needed to meet the 20 percent goal.

At an installed cost of $2.25 million a turbine, an annual operation and maintenance cost of 1.5 percent of the investment, a $0.01 per kWh wheeling charge, and 10 percent losses, the annual cost of power is in the 8 to

11 cents range (absent consideration of any tax credits or other incentives). This compares to an incremental coal-based fuel cost of about 4.5 to 5 cents per kWh for the FWA and EAFB CHPPs.

Figure 20 shows that the expected monthly wind generation pattern more closely correlates to the monthly FWA electric load pattern.

The bulk power system in the interior of Alaska is relatively weak, that is, there are relatively few generators and long-radial transmission lines. From a GVEA system perspective, the Healy and Delta Junction areas are at the ends of its system. The variability in grid-connected wind generation might result in voltage control and stability concerns for the GVEA system.

For much larger systems, a general rule of thumb has been that wind energy penetration of more than 20 percent can be expected to result in operational problems because of the variability of the wind power generation. Recent developments suggest that wind power output may be more predictable than thought, at least on an hour-to-hour and day-to-day basis and that for large systems, greater use of wind power might be possible. Given the much smaller scale of the Interior Alaska power system, as compared to the large systems in the Lower 48, its seems prudent to assume that GVEA's system can absorb about 10 percent of its load from wind power. Levels beyond this will have to be determined through much more comprehensive study and demonstration.

The GVEA system has a peak demand of about 200 MW. Ten percent of this is 20 MW, which is a level consistent with what GVEA is investigating for development. The military installations are quite a bit smaller and may have less ability to respond to changes in wind power generation levels. Their ability to integrate wind power might be much less than 10 percent unless GVEA is willing to do the integration for them.

The installations might be able to utilize 5 MW or less of wind today and up to perhaps 15 MW in 25 years. If the installations pursue wind power development independent of GVEA, it would seem that development would need to be on-installation and connected directly to the base electric system (not through GVEA). This approach could result in operational stability problems for any onsite generation and make integration of significant amounts of wind power (up to 10 percent of load) into the base systems difficult.

Table 35. Delta Junction Area Wind Power Turbines for Fort Wainwright To Meet 10 and 20 Percent Renewable Energy Requirement Using May 2001 to April 2002 Loads.

| Month | Fort Wainwright MWh | kWh | 10% of kWh | 20% of kWh | Avg. Monthly Wind Speed (mph) | Monthly Capacity Factor of Wind Turbine | Est. Delivered Output from 1,500-kW Turbine (kWh)* | No. of 1,500-kW Turbines To Meet 10% kWh | To Meet 20% kWh | Energy Delivered (kWh) 10% | 20% |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 10,109.2 | 10,109,200 | 1,010,920 | 2,021,840 | 13.0 | 60% | 583,200 | 3 | 5 | 1,749,600 | 2,916,000 |
| February | 9,195.5 | 9,195,500 | 919,550 | 1,839,100 | 11.8 | 54% | 480,502 | 3 | 5 | 1,441,505 | 2,402,508 |
| March | 9,453.9 | 9,453,900 | 945,390 | 1,890,780 | 10.6 | 49% | 387,742 | 3 | 5 | 1,163,225 | 1,938,709 |
| April | 7,660.3 | 7,660,300 | 766,030 | 1,532,060 | 9.9 | 46% | 338,221 | 3 | 5 | 1,014,664 | 1,691,107 |
| May | 7,833.5 | 7,833,500 | 783,350 | 1,566,700 | 8.7 | 40% | 261,198 | 3 | 5 | 783,593 | 1,305,988 |
| June | 6,300.0 | 6,300,000 | 630,000 | 1,260,000 | 7.8 | 36% | 209,952 | 3 | 5 | 629,856 | 1,049,760 |
| July | 5,737.1 | 5,737,100 | 573,710 | 1,147,420 | 6.6 | 30% | 150,321 | 3 | 5 | 450,962 | 751,603 |
| August | 5,894.0 | 5,894,000 | 589,400 | 1,178,800 | 6.8 | 31% | 159,569 | 3 | 5 | 478,707 | 797,845 |
| September | 5,981.4 | 5,981,400 | 598,140 | 1,196,280 | 8.5 | 39% | 249,327 | 3 | 5 | 747,980 | 1,246,633 |
| October | 8,181.2 | 8,181,200 | 818,120 | 1,636,240 | 8.8 | 41% | 267,237 | 3 | 5 | 801,710 | 1,336,184 |
| November | 8,923.5 | 8,923,500 | 892,350 | 1,784,700 | 12.8 | 59% | 565,393 | 3 | 5 | 1,696,180 | 2,826,967 |
| December | 9,368.1 | 9,368,100 | 936,810 | 1,873,620 | 11.0 | 51% | 417,557 | 3 | 5 | 1,252,672 | 2,087,787 |
| Annual | 94,637.7 | 94,637,700 | 9,463,770 | 18,927,540 | 13.0 | 45% | 4,070,218.4 | 3 | 5 | 12,210,655 | 20,351,092 |

* At 10 percent losses.

| | | | | |
|---|---|---|---|---|
| **Capital Cost** | **$2,250,000** | **per Turbine (incl. Installation)** | **$6,750,000** | **Total Capital Cost To Meet 10% of Energy** |
| | | | $11,250,000 | Total Capital Cost To Meet 20% of Energy |
| | $33,750 | Annual O & M per Turbine | $101,250 | Total O & M To Meet 10% of Energy |
| | | | $168,750 | Total O & M To Meet 20% of Energy |
| | $0.010 | Wheeling Charge per kWh | $94,638 | GVEA Wheeling Charge To Meet 10% of Energy |
| | | | $189,275 | GVEA Wheeling Charge To Meet 20% of Energy |

| **Approximate Annual Costs** | | **10%** | **20%** |
|---|---|---|---|
| Capital Recovery | | $675,000 | $1,125,000 |
| Operation & Maintenance | | $101,250 | $168,750 |
| GVEA Wheeling | | $94,638 | $189,275 |
| Total Annual Cost | | $870,888 | $1,483,025 |
| Annual Cost per kWh | | $0.1022 | $0.0871 |

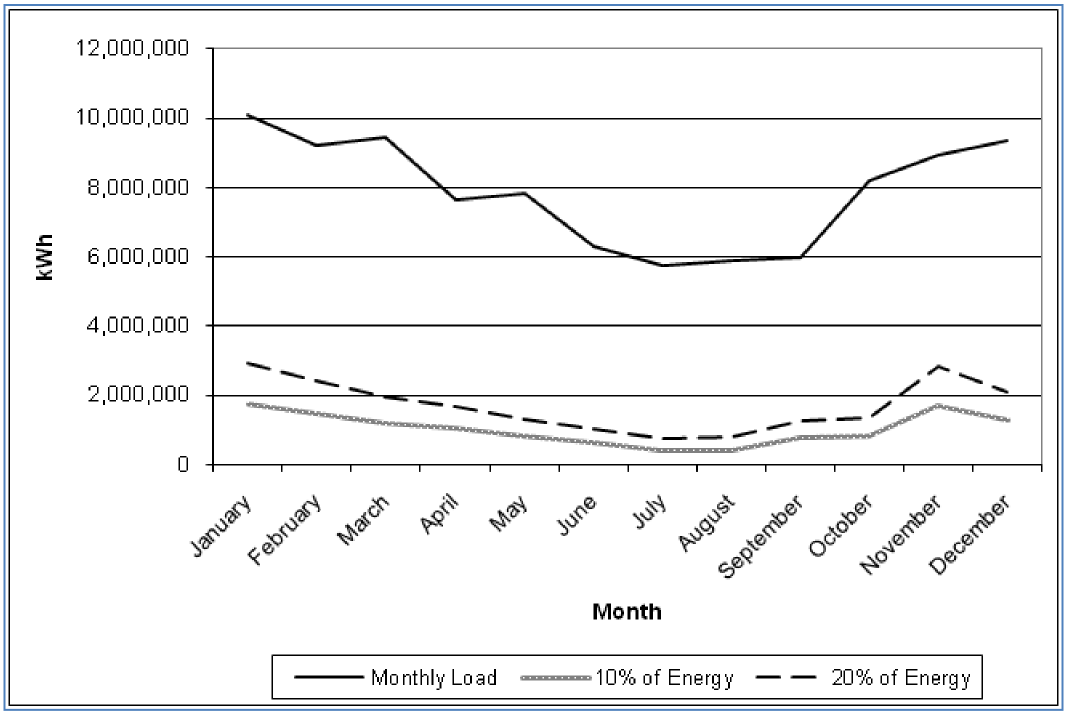



Figure 20. Wind power for FWA/

The intermittent nature and low capacity factors associated with wind turbines means that wind is more likely to supplement generation resources, not provide firm power. Therefore, wind technologies are not considered applicable at this point in time as a firm power resource. Wind generation may become a contributor within the mix of generation technologies that could provide power to the region.

## Geothermal

U.S. Geological Survey maps of geothermal resources indicate no known sources suitable for power production in the greater Fairbanks area. There are a few sources suitable for heating purposes, such as Chena Hot Springs, but no known sources near any of the facilities.

The nearest geothermal resource, Chena Hot Springs, 50 miles away, does not have the capacity or the required temperature to meet either FWA or EAFB heat requirements. At Chena, water from 10 springs, with a combined flow of 221 gpm and maximum temperature of 135 °F, is used to heat a lodge and enclosed swimming pool. Based on geothermometry, the estimated reservoir temperature is 266 to 293 °F. These temperatures are suitable for domestic hot water uses.

Therefore, geothermal is not considered further as an option.

### Municipal Solid Waste (MSW)

The FNSB evaluated the use of municipal solid waste for power generation in the early 1990s and concluded that there were insufficient quantities projected to be available during the life of a project and that the cost of power from a plant was not competitive with other fuels. EAFB is burning refuse-derived fuels (RDF) at its CHPP. Data has been collected on the amounts of solid waste generated at the installations. It is concluded that there is insufficient waste to meet the future energy needs of the installations. The continued use of RDF at EAFB or at FWA or FGA is an issue that is separate from the appropriate approach to meeting the installations long-term energy needs. To the extent RDF can be used to economically offset fossil fuel consumption, it should be continued. It is not competitive as a fuel for firm power supply.

Power generation on the scale required for the installations would involve large quantities of municipal solid waste. Burning of MSW requires an expensive plant, generally estimated at $3000+/kW. For MSW power generation to be cost-effective, a substantial tipping fee for taking the MSW is required.

The installations do not generate sufficient waste to support a MSW waste-to-energy plant (Table 36). The FNSB has its own MSW management program in place. When developing this program, the FNSB rejected the development of a waste-to-energy project.

This concept is not further evaluated.

### Biomass Gases for Gas-Fired CTs

This approach uses digesters to produce the gas fuel for a CT. Similar to the Biomass option above, large quantities of biomass are required and heat requirements for the digesters during the cold weather months would greatly reduce the overall efficiency. This option is not considered to be a viable alternative.

Table 36. Solid waste generation at FWA, EAFB, FGA, CRTC, and FGA.

| Installation | Monthly Average Volume (tons/month) | Composition | Moisture (%) | Caloric Value (Btu/ton) |
|---|---|---|---|---|
| FWA | 150.3 | Housing waste | Unknown | Unknown |
| | 233.53 | Non-housing waste | Unknown | Unknown |
| EAFB | 291.63 | Refuse | Unknown | Unknown |

| Installation | Monthly Average Volume (tons/month) | Composition | Moisture (%) | Caloric Value (Btu/ton) |
|---|---|---|---|---|
| | 62.3 | RDF paper | Unknown | 6,800 |
| FGA Garrison | 8.81 | Burnable (wood, paper and cardboard) | Unknown | Unknown |
| | 19.41 | Mixed | Unknown | Unknown |
| | 64.22 | Bulk | Unknown | Unknown |
| | 1.3 | Ash | Unknown | Unknown |
| | 5.21 cu yd | Asbestos | Unknown | Unknown |
| | 255.58 | Other (sewage sludge, human waste, inert debris) | Unknown | Unknown |
| CRTC | 47.33 cu yd | Burnable | Unknown | Unknown |
| | 66.17 cu yd | Non-burnable | Unknown | Unknown |
| GMD | Unknown | Unknown | Unknown | Unknown |

### Fuel Cells

Fuel cells are a clean source of power currently being demonstrated in relatively small power applications. Current fuel cell systems are still being demonstrated in mainly small power applications. Fuel cells also currently require a source of clean natural gas, which is not available in Interior Alaska. As a result, this technology is not considered further.

### Hydropower

In 1997, a statewide Rural Hydroelectric Assessment and Development Study was conducted. The Study compiled information on 1,144 potential sites statewide. After an initial screening for obvious technical or environmental flaws and the development of preliminary benefit cost ratios for each site, the list was reduced to 131 sites with benefit cost ratios greater than 1. Of these 131 sites, 35 were in the “Yukon” statistical area. Of these 17 sites, the largest was 2.5 MW. Fourteen of the sites were smaller than 400 kW. None of the 17 survived a further economic screening to determine potential feasibility. This suggests that hydropower in Interior Alaska is limited by resource availability.

Interior Alaska climatic conditions also eliminate hydropower as a year-round source. Hydropower is very capital cost intensive and difficult to permit. Hydropower is not considered a viable option.

### Integrated Gasification Combined Cycle and Coal Gasification for Gaseous Boiler Fuel

Integrated gasification combined cycle (IGCC) is a technology with the potential to produce energy from coal with a higher efficiency and lower emissions than conventional coal-burning technologies such as pulverized coal (PC) and CFB units. The approach is to gasify coal to provide a gaseous fuel to CTs. This is technically feasible although there are concerns about the ability to provide a clean fuel in a reliable fashion.

The significant drawback in its use as a boiler fuel is a 20-25 percent efficiency penalty for conversion to a gas with no subsequent gain in the overall conversion to steam and electricity and a substantial investment in equipment to gasify coal and cleanup the gas.

Currently there are two utility-scale IGCC demonstration projects with DOE participation. These projects continue to provide data and produce electricity as part of day-to-day operations for the participating utilities. However, the cost, performance, and emissions of the units have not been as attractive as necessary to compete with current conventional technologies. The IGCC technology also requires a much larger facility than involved in this study to produce favorable economics.

Therefore, the technology is not considered further in either IGCC or as coal gasification for a gaseous boiler fuel.

### Integrated Plasma Gasification Combined Cycle

Integrated Plasma Gasification Combined Cycle (IPGCC) is a process for the conversion of low value fuels/feed stocks, such as coal waste, petroleum coke, biomass, and different waste forms (including MSW), into a low heating value fuel gas. This gas is then used as a primary fuel for a combined cycle gas turbine power plant.

The IPGCC can be viewed as a two-stage processor of a fuel or feedstock. The feedstock is first gasified using high-temperature plasma heating systems at atmospheric pressure. The gas is then cleaned and combusted in the gas turbine to produce electricity. The plasma gasification and vitrification reactor (PGV) cleans the feedstocks by converting them into byproduct fuel gas or “syngas.”

An IPGCC system generally consists of four separate processes:

- feedstock handling
- plasma gasification and vitrification
- gas cooling and clean-up
- gas turbine combined cycle.

The PGV reactor employs plasma torches to heat the reactor to 4,000 to 5,000 °C at atmospheric pressure. At this operating temperature, the PGV process uses a carbon-based catalyst and oxygen-enriched air to cause the hydrocarbon or organic material to undergo partial oxidation, i.e., the hydrocarbon material is converted into carbon and hydrogen molecules by the plasma-generated heat and undergoes partial oxidation to be released as a mixture of $H_2$ and CO. The syngas has a heating value varying from 150 to 300 BTU/scf, which is about 1/3 to 1/6 that of natural gas. All inorganic or non-hydrocarbon based material in the feedstock are simultaneously vitrified into an inert glassy slag.

This process is in use for the disposal of MSW, but has not been demonstrated for power generation on any scale. The City and County of Honolulu, Hawaii has solicited and received proposals from IPGCC developers for a 100,000-tons-per-year MSW disposal project. Honolulu was contacted, as well as the consulting engineers assisting the City/County, and this technology was discussed with them. To their knowledge, there are no operating IPGCC plants. They have also been unable to establish the costs for the proposed projects.

Information supplied by one IPGCC provider is based on a 20 tons per hour project, generating a net 43 MW of electricity. The scale of any project to meet GFMC loads is no more than 45 MW on a single shaft and most likely no more than 10 to 20 MW. Even at this scale, there is not sufficient non-coal fuel available to support this plant. If coal is used, the project becomes a coal gasification project and the need for plasma level temperatures is questionable.

Until the process is proven and the economics demonstrated, the IPGCC technology is not considered further.

### Coal Bed Methane

Coal bed methane (CBM) extraction from the extensive Interior Alaska coal fields represents a possible source of fuel for Interior Alaska.

Typical CBM gas has a heating value in the range of 950 to 1,110 Btus per cubic foot. Depending on the vertical cracking (cleat) characteristics of the coal and the methane release pathway, the methane release potential of various seams may need to be improved by pressurizing and fracturing the coal body. In this case, a simple reciprocating well pump would be located at the well. Both methane and water are pumped to the surface and separated. The process requires extensive surface development. Depending on the coal characteristics, the number of wells installed depends on the flow required and is approximately one well every 250 acres. There is also a great deal of uncertainty over supply at a given location.

CBM development faces significant environmental issues as suggested by the following quote:

> In CBM developments in the Lower 48, people legitimately fear for their clean water wells and private property, which can be severely disturbed by roads, pipelines, drilling rigs, noisy compressors, truck traffic and the general unpleasantness of industrial activity nearby. For surface property owners, the costs greatly outweigh the benefit. " Robin McLean of Alaska Center for the Environment, Daily News Letters, August 2003. He continued: "Unregulated coal bed methane development is irresponsible. A moratorium should be placed on CBM development in Alaska until a sound set of regulatory guidelines can be implemented to avoid the disasters of CBM development in the Lower 48.

The State of Alaska is developing regulations for CBM industry that are intended to address the concerns over its development. Whether the regulations can overcome the negative perceptions is yet to be determined.

The U.S. Supreme Court recently declined to review a lower court decision that the water associated with CBM is a regulated pollutant. This decision will make the environmental mitigation requirements associated with CBM more costly.

CBM exploration in Alaska is in the early stages. Until such time as proven supplies are identified, the amount and probable cost of any supplies is unknown.

Based on the above, coal bed methane is not considered for evaluation.

## Coal-Fired Technologies

### Circulating Fluidized Bed Combustion Boilers

Fluidized combustion bed technology is being operated successfully for a relatively wide range of fuels, including coal. It is a relatively mature technology, particularly when compared to technologies that are in the demonstration phase. Quoting the DOE National Energy Technology Laboratory (NETL) publication *Program Facts, Fluidized Bed Combustion Program*, dated November 2000, "Commercial fluidized bed combustion units operate at competitive efficiencies, cost less than today's units, and have NOx and $SO_2$ emissions below levels mandated by Federal standards." Also quoting from the *Corps of Engineers Technical Manual* TM 5-815-1/AFR 19-6, Chapter 13, Fluidized Bed Boilers, 13-1, "Fluidized bed combustion has now progressed through the first and into the second and third generation of development.

Fluidized bed technology is not new, but has been revived in this country because of fuel costs and the availability of poor quality fuels. Commercial and industrial power plants now have a third type of solid fuel boiler to consider for steam requirements. Economics, fuel pricing, availability of low-grade fuels, and environmental considerations have made the fluidized bed boiler a viable option to evaluate along with the stoker or pulverized coal-fired units. The units can with care be designed to burn a number of fuels, including low-grade coals, lignite, coal mine wastes (culm), refinery gas, wood wastes, waste solvents, sludge, etc." A number of manufacturers and vendors offer commercial systems.

At this scale of new installation, CFBs have largely displaced stoker boilers, which have higher NOx emissions and require $SO_2$ scrubbers to meet best available control technology (BACT) requirements. UCM coal is low sulfur coal and the expectation is that a CFB can meet emissions requirements with in-bed scrubbing. The cost difference between a stoker boiler and a CFB at this scale may slightly favor the stoker boiler; however, the cost of the scrubber for the stoker boiler is much greater than the incremental cost of the CFB. Therefore, a stoker boiler(s) would not be economical compared to CFB and is not considered for a new plant. CFBs are considered proven, viable, and practical.

### Pulverized Coal (PC) Boilers

Pulverized coal boilers are not considered further because they are not as economical as CFBs in the size ranges applicable for the installations. PC boilers require $SO_2$ scrubbers to meet BACT construction permit requirements.

### Pressurized Fluid Bed Combustion (PFBC)

Pressurized fluidized bed combustion is a developing technology for cleaner and more efficient production of power from coal. To improve efficiency, it is desirable to perform gas clean up at elevated temperatures. Also, very high contaminant removal rates are required to have acceptable performance of the gas turbines that are part of the PFBC cycle.

Demonstration scale units have shown need for improvement in gas cleanup technologies to allow reliable commercial use of the technology. Large scale plants, over 100 MW, are necessary for economic application of PFBC. The technology is not judged attractive for further consideration in this study.

### Trigeneration (Heat, Power, and Vapor Absorption Cooling)

This approach is not considered because of the very limited need for cooling. There is no justification for additional equipment and complexity.

## Oil-Fired/Gas-Fired Technologies

### Oil-Fired CTs

Oil-fired CTs in simple cycle (no exhaust heat recovery) are expensive to operate because of the high cost of oil. The electricity generated in a simple cycle is not economical for baseload operation. This option is not considered economically viable. Use of CTs with exhaust heat recovery is evaluated in more detail.

### Reciprocating Engines

Reciprocating engines, particularly oil-fired, are generally not attractive for base-load power generation because of emissions. They also provide small amounts of recoverable heat. Even with the use of natural gas, reciprocating engines are not economically attractive for primary power. Therefore, this is not an option that will be considered further.

### Heating Decentralization

The use of multiple small oil-fired boilers (either steam or hydronic [hot water]) in various locations is a method of providing heat to buildings. This would require delivery and storage of oil with its safety concerns at multiple locations and also could result in portions of the utilidors not being heated. This also has unattractive economics compared to a CHPP burning coal. This option is not considered further as an approach to heating for an installation’s overall needs. However, the use of remote boilers to serve specific locations is a current practice and oil-fired boilers are used for backup in several instances. They are not however, an economical primary source of heat.

Given that the current FWA and EAFB utilidor configuration includes water and wastewater lines that receive freeze protection from the steam lines, removal of the steam lines and loss of the heat creates a significant issue. If, at some point in time, the water and wastewater lines are removed from the utilidors, decentralized heat might be an option. Consideration of the costs of removing the water and wastewater line is beyond the scope of this study.

For the purposes of this study, it is assumed that heat must be provided to the utilidors, making heat decentralization an unattractive alternative.

## Other Options

### Alyeska Pump Station 9 Plant: Power to PS 9, Power (and Maybe Heat) to FGA

Alyeska Pipeline is considering electrifying its PS 9, which is about 3 miles south of FGA and GMD. It appeared that Alyeska might need a heat supply to improve oil flow through the pipeline. It has since been learned that Alyeska uses additives and it does not need heat for the near term future. At some point, Alyeska may need to add heat to the pipeline somewhere south of the Brooks Range, but not necessarily at PS 9. Because Alyeska’s plans are sufficiently indeterminate, this option is not considered further.

### Military Owned Electrical Transmission Line (System)

Consideration was also given to the possibility of the military constructing its own electrical transmission line to interconnect FWA and EAFB. The line could be associated with either a regional solution or provide the ability to transmit power from the existing CHPPs to the other installations.

GVEA estimates that the cost of a new transmission would be $1 million a mile or higher. Given a 25-mile length to link FWA and EAFB, this represents a $25 million investment for a single line.

The NEPA process for siting and permitting a transmission line, as discussed in Chapter 13, requires consideration of alternatives to the proposed action. Because use of GVEA's transmission system would not require construction of a new line, it was determined that military construction of its own transmission line would be unjustified. In addition, it would subject the installations to a single-contingency outage exposure. A better option is to use the GVEA system and support its reinforcement as needed.

## Selected Technologies

On the basis of the above evaluation, the selected technologies for use in evaluating the alternatives are:

- CFBs and STGs for coal-fired options
- CTs and heat recovery steam generators for oil-fired options.

# 13 Ability of Local Providers To Supply Installation Heat and Power Needs

The existing local providers that might be able to provide heat or electricity to the installations are:

- GVEA: for electricity supply and electric transmission at all installations
- Aurora Energy: heat at FWA
- Fairbanks Natural Gas: LNG-derived natural gas at FWA.

There are other entities that have expressed an interest in any privatization efforts at the installations, such as Tikigaq Energy and Utility Infrastructure Group.

The key for any third party provider is a long-term contract at rates that are sufficient to provide the service, recover investment, and make a rate of return. Given a suitable contract, the provider could obtain financing to install the needed plant to provide the service.

Any new entity would face the same situation now faced by the military and would have to construct a new plant to meet the installation's long range needs.

## GVEA

As discussed in "Alaska Utility Regulatory Considerations" (p 22), and Chapter 4, "Golden Valley Electric Association" (p 41), GVEA is the area's electric utility and holds a Certificate of Public Convenience and Necessity (CPCN) for its service area. As a result, it would be very difficult for another entity to engage in selling electricity at the retail level in GVEA's service area.

Alaska has not deregulated its electric utility industry and there is no requirement for GVEA to provide the installations access to non-GVEA sources of power supply. Similarly, there is no requirement for GVEA to provide third parties access to the installations for the sale of electricity.

Because of a number of anticipated load additions (Pogo Mine, electrification of PS 9 and GMD), GVEA needs to add generation capacity to its sys-

tem; its existing generation resources will not provide a suitable amount of reserves to assure reliable supply. The result is that, while GVEA could serve all of the installation's electricity needs, it would need to add generation to do so. It would also need to upgrade its substations and transmission lines to serve FWA and EAFB.

GVEA has expressed interest in the privatization of the heat and power functions at FWA or FGA. If it were to become the owner of the existing CHPPs, it would face the same questions about long-term provision of heat and power that are being addressed by this study. Provision of heat is not GVEA's primary mission. Any arrangement for providing heat or electricity to the installations could not have a detrimental affect on its other customers. If it did, the RCA would not approve the arrangement.

Our conclusion is that while GVEA could provide electricity or heat, it would have to install a new plant to do so and its long-term solution(s) would not be that much different from the alternatives developed for evaluation.

## Aurora Energy

AE, a subsidiary of UCM, operates a coal-fired power plant in Fairbanks and provides district steam and hot water heat service to a portion of Fairbanks. Low-temperature, hot water district heating also is provided to portions of downtown Fairbanks. AE acquired the City of Fairbanks district heat system in 1998. AE currently serves 148 district heat customers. AE experienced a heat peak load of 53,500 pounds per hour (lb/hr) (steam) in January 2000 at a temperature of -36 °F. Its Chena Power Plant has three boilers, 1, 2, and 3, that are rated at 40,000 lb/hr each. These boilers provide steam to the 5-MW Chena 1 STG, and to the 2.5-MW Chena 2 STG. They were installed in 1951 through 1953. The Chena 5 boiler is rated at 200,000 lb/hr and provides steam to the 20-MW Chena 5 STG.

AE annually sells 120,000 MWh (13.7 average MW) of "take-or-pay" electricity to GVEA; GVEA is obligated to pay for the 120,000 MWh, whether it actually takes that amount or not. AE also will sell GVEA additional electrical energy if requested by GVEA and AE can do so without incurring additional startup costs. The prices paid are adjusted annually by the percentage by which prices from GVEA's other power sources change. This power sales contract with GVEA expires in 2017.

AE heat loads are considerably less than the heat loads at either FWA of EAFB. For AE to serve FWA, AE would need to build a new heat plant or a new combined heat and power plant, or possibly take over the existing CHPPs at the installations. The key to this would be a long-term energy sales contract with the military to allow financing of the needed infrastructure.

AE could not sell electricity directly to the military under current Alaska regulatory conditions. It does not have an RCA CPCN to do so. If it were to become the privatized owner/operator of the existing CHPPs, it would face the same situation now faced by the installations, aging infrastructure and increased costs of maintenance. Our conclusion is that AE is not positioned to provide FWA with heat in the near term and in the long term it would need to construct facilities similar to one of the alternatives evaluated in this study.

## Fairbanks Natural Gas

As discussed in "Fuels in Interior Alaska" (p 30) Fairbanks Natural Gas (FNG) is importing LNG into the Fairbanks area by truck, vaporizes the gas and distributes it over an underground gas distribution system. It has a base of about 560 customers and annual sales of about 400,000 million cu ft. Its commodity sales price is currently $8.26 per MMBtu. It competes against oil-fired heat.

For FNG to provide service to FWA from its existing system, it would have to obtain a CPCN to expand its service area onto FWA. A possible alternative would be for it to serve an installation as a single customer (wholesale) and avoid the need to obtain a CPCN.

Our conclusion with regard to FNG's ability to provide service is similar to that for GVEA and AE. While it does not have the existing ability to provide service, it is interested in growing its business and would work with the military to develop a beneficial arrangement. At its current prices, it is an expensive fuel source for a CHPP.

# 14 Heat and Power Alternatives at FGA and GMD

This Chapter discusses our conclusions with regard to providing heat and power to FGA and GMD. The alternatives and solutions for these two installations are more straightforward because of limited fuel choices, the distances from FWA and EAFB, and the relatively young age of the boilers. Both installations also get their electricity needs from the GVEA transmission/distribution system.

## FGA Garrison—Current Situation

### *Heat*

Over the past 40 years, FGA has met its heating needs from a CHPP that burns diesel fuel–arctic (DFA). This CHPP includes three 50,000-lb/hr boilers, two of which were replaced with new boilers in 1993. The third was refurbished at the same time using equipment and materials from the two boilers that were replaced.

The steam heat is distributed in the cantonment area using a utilidor system that also includes water and sewer lines. Heat loss from the steam and condensate return lines provides freeze protection to the water and sewer lines. The utilidor system contains asbestos insulation on the steam and condensate lines. The insulation has been encapsulated and the utilidors are washed out twice a year.

Some of the facilities at FGA use a hot water system within the building(s).

### *Power*

FGA is interconnected to GVEA through a 2.5/3.125 MVA, 24.9/4.16 kV transformer. Power deliveries to the base are through this transformer. The service from GVEA is over GVEA's distribution system. FGA is not directly connected to the GVEA transmission system.

FGA has three 1-MW and two 1.25-MW engine generators to provide backup power supply for critical loads and to meet peak load requirements greater than 3.125 MVA, the GVEA transformer rating.

The FGA electrical system serves the CRTC over Feeder 9, which originates from its main switchgear. CRTC is anticipating a nominal increase in its electrical loads. It is also anticipating a separate 5 MW load, which will have to be served separately from the FGA electric system.

Figure 21 shows the heat and electricity configuration at FGA.

*Ability to Privatize*

Based on our investigations, privatization of the FGA CHPP, electric distribution system and heat distribution system should be possible.

Both the CHPP and the utilidor system contain asbestos, which may complicate privatization efforts.

### GMD—Current Situation

*Heat*

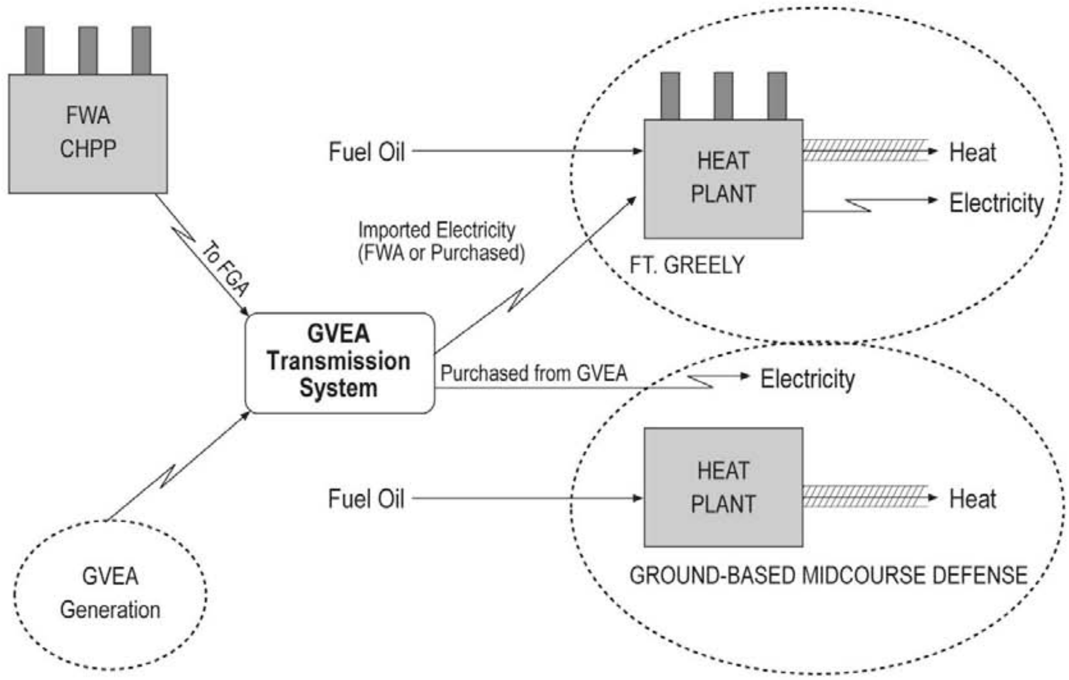
GMD heat needs are met by two new 6.695 MMBtu/hour, 670 gallons per minute (gpm) hot water boilers burning DFA. The utility building housing the boilers is sized for the future addition of two more hot water boilers.

The hot water is distributed around the installation using a utilidor system (approximately 2.6 miles). The hot water distribution lines are sized to meet anticipated future loads.

There is no interconnection between FGA and GMD for heat.

*Power*

GMD is interconnected to GVEA through a 12/16/20 MVA, 138/13.8 kV substation at GMD. The substation is fed from GVEA's Jarvis Creek 138 kV line. GMD's electrical needs are purchased from GVEA. The substation is interconnected to the main GMD electrical switchgear by a single underground circuit. Provision has been made for a second future circuit to serve the switchgear.




**FGA Alternatives:**

1. **Continue as is:**
   - 10-year-old steam boiler plant for heat
   - Importing electricity from FWA (should purchase from GVEA)
2. **Possible eventual conversion to hot water for heat, possible interconnection to GMD for heat and electricity backup**

**GMD Alternatives:**

1. **Continue as is:**
   - New plant in 2003/2004
   - Hot water boilers for heat
   - Purchasing electricity from GVEA
   - Onsite backup electrical generation
2. **Possible interconnection with FGA for heat and power backup for FGA**

*FIGURE 17-1*
**FORT GREELY AND GROUND-BASED MISSILE DEFENSE HEAT AND ELECTRICITY OPTIONS**
**CH2MHILL**

Figure 21. Heat and electricity configuration at FGA

For critical loads, there are backup engine generators that use DFA for fuel and UPS systems. GMD is in the process of procuring and installing four 2-MW engine generator sets for use as emergency backup. Initially, the units will be housed in a temporary facility and eventually moved to a permanent facility.

There is no electrical interconnection between GMD and FGA.

As part of its power supply options analysis, GMD evaluated moving the GVEA 23-MW Chena #6 CT to FGA to provide backup power supply; however, new diesel engine generators were selected as the more economical alternative.

Figure 21 shows the heat and power configuration at GMD.

*Ability to Privatize*

The Boeing Company currently operates the GMD. In this sense, GMD operations are privatized. This may change in the future.

### Fuel Options

The fuel options at FGA and GMD are limited. Coal is not available without trucking it. The Alaska Railroad line ends at EAFB, and there is no rail service to the area. The DFA fuel is trucked from the North Pole refineries and is stored onsite in two 30,000-gal tanks (FGA) and two 75,000-gal tanks (GMD).

There is no natural gas supply. It would be possible to truck LNG to FGA and install storage and vaporization facilities to serve the central heat plant. The cost to provide LNG/natural gas would be greater than the cost to provide DFA because of the need for new infrastructure and comparable fuel costs.

PS 9 is about 3 miles south of FGA. The proposed route of the ANGTS comes to within about 25 miles of FGA. If the pipeline is built, there will be a relatively nearby source of natural gas. At that time, an evaluation of the feasibility of converting to natural gas should be done. Assuming natural gas has a $1 per MMBtu cost advantage over DFA, and using FGA 1996 fuel consumption levels (which are representative of today's usage) the present value of the annual fuel savings over 20 years would be about $2.6 million. The FGA boilers could be retrofit with natural gas burners or

a simple-cycle CT cogeneration plant could be evaluated for both heat and power supply. Natural gas burner retrofit should be easily justifiable based on the fuel savings. An order of magnitude cost estimate for a burner retrofit is $250,000.

### Other Facilities in the Area

PS 9 has a small heat load that is served by waste heat from the turbine-driven pumps. Alyeska is in discussions with GVEA about electrifying the pump station and no longer using turbine driven pumps.

Alyeska was contacted about the possible need for heat. We learned that any need for heat is years away and could be met at locations south of the Brooks Range, not just PS 9.

### Regional Solutions

As previously discussed, FGA is 85 miles to the south of EAFB and 110 miles from FWA. FGA does not generate to meet its own electrical needs. It gets power from FWA, wheeled over the GVEA system, and also buys power from GVEA. FGA does have onsite engine generators to generate electricity during outages or for peaking.

From information provided by FGA, it does not appear that future steam loads or electrical loads will grow much beyond current levels. As a result, the existing infrastructure (boilers, engine generators) has sufficient capacity to meet projected needs through 2028. The only exception to this might be a 5-MW electrical load being anticipated by CRTC. This load would need to be served independently of the FGA electrical system. The costs to do this would be part of the new facility's costs.

There is no advantage to a regional heat solution for FGA and GMD, and the cost of heat transmission would be prohibitive. Both use DFA for fuel and there would be no significant efficiency improvement. The boilers at both facilities are relatively new (10 years old or less) and significant additional capital investment is not anticipated at FGA. (Privatizing the heat requirement at FGA also appears a sensible alternative) The GMD investments for heat are relatively small.

FGA is anticipating repair and upgrade of its utilidor system. Preliminary discussions with FGA DPW representatives indicate that conversion of the existing steam system to hot water may be an attractive solution. If the

system is converted to hot water distribution, the old Boiler No. 3 could be replaced with a hot water boiler and the other boilers replaced with hot water boilers at the appropriate time. This conversion would need to provide redundancy of hot water supply during the transition of the boilers from steam to hot water. This could be done with an auxiliary heat facility to provide the needed redundancy.

If the steam heat distribution system is converted to hot water, it might be appropriate to interconnect the FGA and GMD systems and either have one centralized plant or provide backup using the interconnection.

As described, the heat alternatives are:

- Continued operation of the existing FGA (steam) and GMD (hot water) central heat plants for their economic lives. This approach should be viable for the period of this study.
- Convert the FGA heat distribution system from steam to hot water and at the appropriate time, convert the existing heat plant to hot water or replace it with a hot water heat plant. Depending on the availability of fuels at the time, the fuel could be DFA or natural gas.
- If the FGA heat distribution system is converted to hot water, interconnect the FGA and GMD utilidor systems and at a minimum use the interconnection for backup. Depending on the age of the GMD plant at that time, it might be appropriate to build a new heat plant at FGA to serve both installations. Using the GMD heat plant to serve FGA might require expansion of the GMD Utility building to house the necessary boilers.

For electricity, the facilities are already pursuing regional solutions by purchasing their electricity needs from offsite. If the military were to build a regional power plant to serve its needs, power could be provided to either or both installations instead of purchasing from GVEA.

If a new 5 MW load, or any significant load growth, occurs at CRTC, separate and new electric facilities will be required to serve the load.

### Conclusion

Our evaluation is that the present approach to heat and power at FGA and GMD is appropriate.

### Economic Analysis of Wheeling FWA Power to FGA

Our analysis indicates that the cost of generating power at FWA and wheeling it to FGA is more expensive than if FGA were to purchase all of its electrical needs from GVEA.

At a cost of $50.30 per ton for 7,800 Btu per pound coal ($3.22 per MMBtu), a conversion efficiency of 78 percent for the production of steam in the FWA boilers, and 30 percent for the conversion to electricity, the fuel cost to generate a kWh is $0.0473. Add to that the 11.1 percent losses incurred in wheeling the power to FGA and a $0.0115 per kWh wheeling charge and the delivered cost is $0.064 per kWh. The same kWh can be purchased from GVEA by FGA for $0.05837. In addition, FWA over-generates somewhat compared to the contractual limits for wheeling, and this adds another 3.3 percent to the costs.

### Recommendations

1. FGA purchase all of its electricity needs directly from GVEA; do not wheel power from FWA.
2. FGA maintain the CHPP and standby engine generators as is being done now. Meet FGA heat loads from the CHPP. It is not necessary from a capacity standpoint to maintain all five engines; two or three engines would provide sufficient capacity.
3. FGA should investigate the conversion of the existing steam heat distribution system to hot water. If this were done, a centralized hot water approach to heat at FGA would be appropriate.
4. When natural gas becomes available in the FGA area, evaluate conversion of the CHPP to natural gas or the installation of a natural gas-fired cogeneration plant to meet both heat and electricity needs.
5. Replace the existing GVEA existing 3.125 MVA transformer with one rated 5 MVA to eliminate the existing capacity constraint on deliveries across the transformer. A system electrical study should be done to verify that this would not result in any electric system components being underrated.
6. Pursue privatization of the electrical and heating systems at FGA.

# 15 Alternatives For Evaluation

This Chapter discusses the alternatives that have been evaluated as potential long-term solutions for heat and electricity for FWA and EAFB on either a regional basis or an installation-specific basis.

First, the alternatives were identified and then developed for the installation or the regional solution. The alternatives provide a meaningful basis for comparison. They have not been optimized, and options within an alternative have not been separately evaluated. Once a given alternative is selected, further analysis is needed to determine the specific configuration.

## Alternatives Overview

Two basic concepts for the provision of heat and electricity to FWA and EAFB are considered:

- participation in a *regional* solution
- *installation-specific*, onsite heat and electricity generation.

The evaluation is based on the advantages of combined heat and power generation from a fuel efficiency perspective. It is more fuel-efficient and therefore more economic and environmentally friendly to cogenerate electricity and heat than it is to generate each separately.

While the existing CHPPs are aging, there is sufficient boiler capacity to meet projected heat needs at both FWA and EAFB for the 25-year period of this study. Electric loads are projected to increase more rapidly than the heat loads; both FWA and EAFB have a fixed amount of STG capacity, which will be inadequate to meet their respective projected electricity loads. Relatively speaking, there is a greater need for additional electric generation capacity than there is for heat generation capacity.

The alternatives evaluated are briefly described below.

### Regional

Within the regional solution concept, there are two basic approaches:

1. Regional power plant that generates to meet the electricity needs of the GFMC
2. Regional CHPP that generates both heat and electricity to meets the needs of FWA and EAFB for heat and the GFMC for electricity

For a regional power plant, it is necessary to continue to operate the onsite CHPPs for heat and the associated fuel-efficient power generation.

A new regional power plant or CHPP could be:

- coal-fired, in which case, CFBs and STGs would be used
- oil-fired or oil distillate–fired CTs and HRSGs would be used.

The regional analysis evaluates four Alternatives, a regional power plant fired by either coal or oil (Regional Alternatives 1 and 2) and a regional CHPP fired by either coal or oil (Regional Alternatives 3 and 4).

### Installation-Specific

Within the installation-specific concept, there are two basic approaches:

- continued use of the existing CHPP, including repair and upgrade
- construction of a new CHPP.

Continued use of the *existing* CHPP involves the following basic alternatives:

- repair only, no increases in capacity are made (Alternative 1)
- upgrade the plant by adding STGs to take advantage of existing boiler capacity, allowing the plant to meet electrical load growth (Alternative 2)
- repair the plant and operate as fuel efficiently as possible ("follow the heat curve") (Alternative 3)
- add new boilers and STGs to the existing CHPP (this is in EAFB's plan for 2012) (Alternative 4) (this alternative was evaluated only for EAFB).

A *new* onsite CHPP could be:

- coal-fired, in which case, CFBs and STGs would be used (Alternative 5)
- oil-fired or oil distillate–fired CTs and HRSGs would be used (Alternative 6).

### Comparative Installation-Specific Alternatives

For comparison of the regional alternatives to installation-specific alternatives, the following installation-specific alternatives were combined:

- FWA Alternative 1 and EAFB Alternative 1 – Repair only
- FWA Alternative 2 and EAFB Alternative 2 – Add STG capacity

- FWA Alternative 3 and EAFB Alternative 3 – Repair only, “follow the heat curve”
- FWA Alternative 1 and EAFB Alternative 4 – Add STG capacity at FWA, add new boilers and STG at EAFB
- FWA Alternative 5 and EAFB Alternative 5 – New coal-fired CHPPs
- FWA Alternative 6 and EAFB Alternative 6 – New oil-fired CHPPs.

The individual alternatives are discussed in more detail below.

These alternatives are summarized in Table 37.

## Regional Solutions

Possible regional solutions include a central power plant with heat and fuel-efficient electricity (installation-specific Alternative 3) continuing to be provided onsite for each installation or a CHPP with heat and electricity transmitted to the appropriate installation(s). A regional power plant would require upgrade of the interconnections to the GVEA system. A regional CHPP would require the construction of a heat transmission system to move the heat from the CHPP to the other installation(s).

### Regional Heat

Of the four installations, the two largest heat loads are FWA and EAFB, with FWA having a somewhat greater load on an annual basis (approximately 1.1 million klbs at FWA compared to 1 million klbs at EAFB). These installations are approximately 20 miles apart. However, actual distance for a heat transmission line would most likely be 25 miles. FGA and GMD are 85 miles to the south of EAFB, too great a distance to consider heat transmission for the relatively small loads involved.

Table 37. Overview of alternatives.

| | Alternative | Primary Heat | Primary Power | Backup Heat | Backup Power |
|---|---|---|---|---|---|
| *Regional*[1] | | | | | |
| Regional Power Plant<br>A Regional Power Plant to Generate Electricity To Meet Installation Needs Over and Above the Installation's On-site Power Generation (Requires Continued Operation of Existing CHPPs). | **Alternative 1:** Coal-fired CFB/STG Power Plant | Existing CHPPs | New Regional Plant<br>Existing CHPPs ("follow the heat curve mode") and new regional power plant | Existing CHPPs<br>Aux. Heat Plants (EAFB only) | Existing CHPPs<br>Onsite backup generation—GVEA. |
| | **Alternative 2:** Oil-fired CT/HRSG Power Plant | | | | |
| Regional Heat And Power Plant<br>A Regional CHPP to Provide Both Heat and Electricity to the Installations. | **Alternative 3:** Coal-fired CFB/STG CHPP | New Regional CHPP | New Regional CHPP | Existing CHPPs<br>Aux. Heat Plants (EAFB only) | On-site backup generation and GVEA. |
| | **Alternative 4:** Oil-fired CT/HRSG CHPP | | | | |
| *Installation-Specific* | | | | | |
| Continued Operation of the Existing FWA and EAFB CHPPs | **Alternative 1:** Repair existing CHPP(s) | Existing CHPPs | Existing CHPPs | Existing CHPPs<br>Aux. heat plants (EAFB only)<br>Heat Storage | On-site backup generation<br>GVEA. |
| | **Alternative 2:** Repair and add STG capacity. | | | | |
| | **Alternative 3:** Repair and operate in "follow the heat curve" mode. | | | | |
| | **Alternative 4:** (EAFB only) Add new CFB and STG, abandon 2 old boilers. | | | | |
| New On-site CHPPs | **Alternative 5:** New coal-fired CHPP using CFB/STG. | New CHPP | New CHPP | Existing CHPPs<br>Aux. heat plants (EAFB only) | On-site backup generation<br>GVEA. |
| | **Alternative 6:** New oil-fired CHPP using CT/ HRSG | | | | |

[1] Plant Location: EAFB, FWA, or somewhere in-between ("outside the fence"). EAFB offers advantages of security and it is outside of the Fairbanks CO management/NAA. Presumably, FWA would import its electricity and heat from the regional plant; this requires FWA to have backup for electricity and heat. For a plant located outside of both FWA and EAFB, both plants would import heat and electricity, which requires backup capability at both installations for electricity and heat. For FGA and GMD, the plant would provide power only.

A long-distance heat transmission line would need to consider the transmission medium (hot water or steam). For a 25-mile distance, hot water is the more logical choice. Insulation requirements would need to be established based on the economic tradeoff between energy losses and insulating values. Energy losses could be expected to be no more than 5 to 10 percent.

For this evaluation, it is assumed that the heat transmission system configuration would be a shallow utilidor system rather than direct burial. This would provide a significant advantage in terms of maintenance and system longevity. A detailed geotechnical survey of the route would be required before any decision on the type of transmission system.

### Regional Power

#### *Electricity Generation*

A regional power plant can offer some economy of scale advantages, although at the scale being considered here, the benefits are minimal. In the lower 48, the most economic size power plant is 250 MW or greater. A regional power plant for military loads during the study period is about 100 MW with multiple units required to provide redundancy for reliability.

#### *Transmission*

A regional solution to electricity supply requires a high-voltage transmission system to transmit the power from the generation site to the end-use location. This could be done with a military transmission system or by using the GVEA system. There is no military transmission system now; new facilities would have to be permitted and constructed.

The addition of new high-voltage transmission lines to serve the installations could:

- Provide a military only transmission system or path to interconnect the installations. This would allow the military to avoid use of the GVEA transmission system and the associated wheeling charges.
- Reinforce the GVEA transmission to improve the reliability of service to the installations.

A military only system would raise a number of institutional issues, particularly utility regulatory ones. A military transmission system requires

that a Regulatory Commission of Alaska Certificate of Public Convenience and Necessity be obtained.

Also, military only transmission facilities could be perceived as an unnecessary duplication of the GVEA system. Opponents can be expected to argue that a solution taking maximum advantage of the GVEA transmission system is less harmful to the environment and more cost effective.

A military only system would also suffer from numerous single contingency outage exposures, high costs relative to benefits, and possible state regulation. It would also require operation and maintenance and perhaps an inter-Service agreement on the funding. For these reasons, a military only transmission line or system is not regarded as a realistic alternative.

Use of the GVEA transmission system with GVEA responsible for system improvements and reinforcements to serve the military loads is assumed. With a suitable contract GVEA can be expected to fund system reinforcement. The agreement would need to provide GVEA with sufficient revenues over a period of time to justify the GVEA investment.

### Regional Alternatives

The following regional alternatives were identified:

*Construct a New Regional Power Plant (Coal or Oil)*

A new regional power plant could be constructed to meet the installations electrical loads. The plant could be either primarily coal or oil fired.

Installation heat requirements would be met through continued operation of the existing CHPPs. At FWA and EAFB, the existing CHPP plants would “follow the heat curve” after the regional facility was operational. At FGA and GMD, the heat plants would continue to operate as now.

*Construct a New CHPP and Transmit Heat to Installations (Coal or Oil)*

Under this approach, the existing CHPP would be replaced with a single CHPP that could be located on one installation or located between installations. As discussed above, the FWA and EAFB are the most likely candidates for a regional CHPP. The heat transmission requirements would be the same independent of the CHPP location because the heat loads are approximately the same.

The most likely location would be outside Fairbanks to avoid the CO management/NAA and to reduce or eliminate the FWA cooling pond ice fog issue. To the extent the plant could be located as close to a straight-line as possible between the two installations, heat transmission distance would be minimized. For evaluation purposes, it was assumed that the plant would be located on EAFB. Locating the plant "outside the fence" of both FWA and EAFB would not change the plant configuration, but would introduce additional security issues for heat transmission to two installations instead of the one (FWA) that has been assumed. A plant "outside the fence" would also incur some additional cost for land acquisition. This cost was not included in the evaluation.

## Regional Alternatives Definition

Figure 22 shows a schematic representation of the regional alternatives.

*Alternative 1: Coal-Fired Power Generation Only (Estimated Capital Cost—$308,811,000)*

This option is based on meeting the peak electrical demands for all the facilities; FWA, EAFB, FGA (including the CRTC feed), and GMD, using coal in CFBs. The plant could be located at FWA, EAFB, or a location in between FWA and EAFB. A specific location has not been selected for this analysis, but preferable attributes would include being near the existing railroad, transmission lines in close proximity, having available water, and outside the Fairbanks area CO management/NAA. The CO non-attainment issue results in FWA not being a preferred location. For purposes of discussion, the location will be based on EAFB, but the design and cost are considered to be the same as for a plant located between FWA and EAFB. The sizing basis will consider the individual electric peaks being concurrent and allow 10 percent of the gross generation for auxiliary power. Since most of the electrical demand would be FWA and EAFB, no allowance is included for transmission losses. Once the new facility is operational, the heating demand at each facility will be supplied by the existing plants; following the "heat curve" for FWA and EAFB. Operation prior to the availability of the new facility will be based on "Repair: No Added Capacity" for FWA and EAFB (Alternative 1 at each facility).

The estimated peak electrical demand in 2028 is 91.0 MW, consisting of 36.3 MW for FWA, 29.7 MW for EAFB, 10.1 MW for FGA (includes CRTC) and 14.9 MW for GMD. Since FWA and EAFB will be following the heat curve, they will deliver about 22.3 MW, 11.8 MW and 10.5 MW respective-

ly, at the peak heating demand. Assuming the electrical and heating demand are concurrent, the regional power plant will need to provide 68.7 MW. Considering the auxiliary power, the plant will require a capacity of about 76.3 MW. Providing this capacity based on four installed units with three operating units for the n-1 condition requires each STG to be nominally 26 MW.

A STG of this capacity would typically have throttle conditions of 850 psig/900 °F and feedwater heating to about 400 °F. The throttle flow to provide 76.3 MW with the above conditions is about 765,000 lb/hr. Using four installed boilers results in each boiler having a capacity of about 255,000 lb/hr to also support the n-1 condition. Therefore, the plant is based on four 255,000 lb/hr boilers and four 26-MW STGs.

This alternative involves constructing a new major facility requiring PSD/NAA permitting. The CFBs will have SNCR for NOx control, limestone injection to the fluidized-bed for $SO_2$ control, and baghouses for particulate control. The combustion efficiency via state-of-the-art controls will provide the basis for CO and VOC emissions. The emission rates will be similar to the Alternative 5 new plants at FWA and EAFB.

The generators for the STGs would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability could be incorporated in the design of the new boilers. Burners for fuel oil or natural gas and appropriate combustion controls and burner management systems would be required. An inert material such as sand would be required in the bed to allow the CFBs to maintain their heat transfer characteristics with either fuel oil or natural gas.

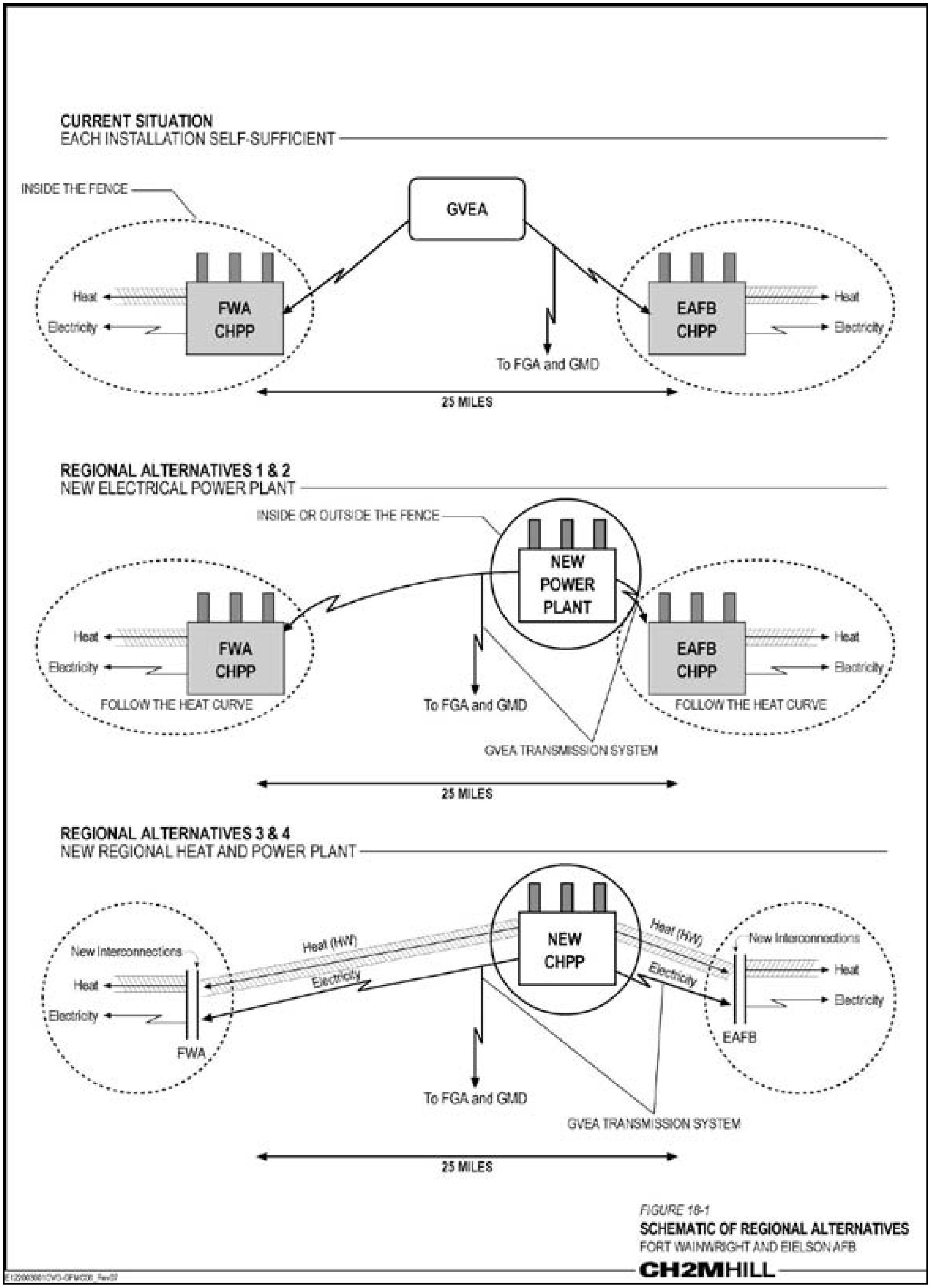



Figure 22. Regional alternatives.

The general scope of this alternative includes a new standalone plant consisting of four CFBs each with SNCR and baghouses for emission controls, four STGs, air-cooled condensers, coal handling, limestone handling, ammonia storage and transfer, ash handling, balance of plant systems, building, two mile rail spur extension, and substation.

Evaluation of this option includes the capital investment for the new plant, the O&M costs associated with the new plant, paying a wheeling charge to GVEA, and operation of the CHPPs at both FWA and EAFB. The purchase of electricity from GVEA should be minimal since the plant can provide the peak demand in the n-1 condition.

This alternative has the following advantage(s):

- economy of scale
- reduced emissions in the Fairbanks CO management/NAA
- improvement in fuel efficiency.

This alternative has the following disadvantage(s):

- capital cost
- high operation and maintenance costs because of continued operation of the aging existing CHPPs
- reliance on GVEA transmission system to deliver power to three of the four installations
- for the oil-fired Alternative 2, the high cost of oil.

*Alternative 2: Oil-Fired Power Generation Only (Estimated Capital Cost—$165,230,000)*

This option will be based on meeting the peak electrical demands for all the facilities; FWA, EAFB, FGA (including the CRTC), and GMD, using oil (DFA or naphtha) in a combined cycle configuration (CT with HRSG providing steam to drive a STG). A specific location has not been selected for this analysis, but preferable attributes would include being either near the existing fuel oil line from the North Pole area refineries to EAFB or where a supply line can be easily provided, transmission lines in close proximity, having available water, and outside the Fairbanks area CO management/NAA. Similar to Alternative 1, it is assumed the plant location is at EAFB and the design and cost are the same regardless of location. The sizing basis will consider the individual electric peaks being concurrent and allow 5 percent of the gross generation for auxiliary power. Since most of the electrical demand would be FWA and EAFB, no allowance is included

for transmission losses. The heating demand at each facility will be supplied by the existing plants, following the "heat curve" for FWA and EAFB. The estimated peak electrical demand in 2028 is 91.0 MW, consisting of 36.3 MW for FWA, 29.7 MW for EAFB, 10.1 MW for FGA (includes CRTC) and 14.9 MW for GMD. Since FWA and EAFB will be following the heat curve, they will deliver about 22.3 MW, 11.8 MW and 10.5 MW respectively, at the peak heating demand. Assuming the electrical and heating demand are concurrent, the regional power plant will need to provide 68.7 MW. Considering the auxiliary power, the plant will require a capacity of about 72.4 MW. Providing this in four installed units with three operating units for the n-1 condition requires each combined cycle to be about 24 MW.

A potential configuration for each combined cycle unit is a General Electric LM2000 aeroderivative CT with a duct-fired HRSG (HRSG) providing steam to a STG. This configuration can generate 24 MW (gross), 19.0 MW from the CT and 5 MW from the STG with a modest amount of duct-firing. Full load operation without duct firing has a heat rate under 7,700 Btu/kWh. While there are other potential CTs and configurations available, the GE LM2000 configuration has been used here as a basis because it is representative and performance and cost information is readily available. The multiple units provide good operating flexibility over the load range and with the steam side using a common header to supply the STGs, high reliability is achieved.

This alternative involves constructing a new major facility requiring PSD/NAA permitting. NOx emission controls consist of water injection in conjunction with SCR. The $SO_2$ emissions will be a function of the sulfur level in the fuel oil. Ultra-low sulfur fuel oils are not readily available in the Fairbanks area, but the low sulfur fuels available should result in acceptable $SO_2$ emissions. CO and VOCs will be reduced via high combustion efficiency and oxidation catalyst. Formaldehyde is the primary concern for HAPs and could equal the total HAPs from the coal-fired alternatives. In summary, overall emissions should be as low as the best coal-fired alternative and probably better.

The generators for the CTs and STGs would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability for the CTs and duct-firing of the HRSGs would require natural gas. Dual fuel capability with fuel oil and natural gas are relatively common for CTs and the HRSGs and involve different combustors and burners, respectively. Natural gas would result in lower emissions and reduced maintenance compared to fuel oil.

The general scope of this alternative includes a new standalone plant consisting of four combined cycle units (each consisting of a CT, single-pressure HRSG with duct-firing, and STG), SCRs, CO catalyst, oil receiving, storage, and transfer; balance of plant systems, building, and substation.

Evaluation of this option includes the capital investment for a new plant, the O&M costs associated with the new plant, paying a wheeling charge to GVEA, and operation of the CHPPs following the heat curve at both FWA and EAFB. The purchase of electricity from GVEA should be minimal since the plant can provide the peak demand in the n-1 condition.

This alternative has the following advantage(s):

- economy of scale
- reduced emissions in the Fairbanks CO management/NAA
- improvement in fuel efficiency.

This alternative has the following disadvantage(s):

- capital cost
- high operation and maintenance costs because of continued operation of the aging existing CHPPs
- reliance on GVEA transmission system to deliver power to three of the four installations
- for the oil-fired Alternative 2, the high cost of oil.

*Alternative 3: Coal-Fired CHPP with Long-Range Heat Transmission (Estimated Capital Cost—$590,925,000)*

This option will be based on meeting the peak electrical demands for all the facilities; FWA, EAFB, FGA (including the CRTC feed), and GMD; and the peak heating demands for FWA and EAFB using coal in CFBs. The plant could be located at FWA, EAFB, or a location in between FWA and EAFB. A specific location has not been selected for this analysis, but preferable attributes would include being near the existing railroad, transmission lines in close proximity, having available water, allowing a relatively

direct routing of the heat transmission piping, and outside the Fairbanks area CO management/NAA. The CO non-attainment issue results in FWA not being a preferred location. For purposes of discussion, the location will be based on EAFB, but the design and cost are considered to be the same as for a plant located between FWA and EAFB. The long distance heat transmission piping is assumed to be 25 miles in length to allow for a less than direct routing from the plant to FWA and EAFB. The sizing basis for the CHPP will consider the individual electric and heating peaks being concurrent. The sizing basis also allows 10 percent of the gross generation for auxiliary power and a 10 percent increase in the heat demand to cover losses associated with the conversion to hot water for transmission and heat losses during transmission. Since most of the electrical demand would be FWA and EAFB, no allowance is included for electrical transmission losses. The estimated peak electrical demand in 2028 is 91.0 MW, consisting of 36.3 MW for FWA, 29.7 MW for EAFB, 10.1 MW for FGA (includes CRTC) and 14.9 MW for GMD. FWA and EAFB will require approximately 740,000 lb/hr (355,300 and 317,200 plus 10 percent) of steam to meet the peak heating demand. Considering the auxiliary power, the plant will require an electrical capacity of about 101 MW. Providing this in four installed units with three operating for the n-1 condition requires each STG to be about 34 MW.

Using STG throttle conditions of 850 psig/900 °F in a cycle using feedwater heating to around 400 °F results in the 740,000 lb/hr of heating steam generating about 25 MW. The approximate remaining 76 MW require a throttle flow of about 765,000 lb/hr, resulting in a total throttle flow of 1,505,000 lb/hr. Using four installed boilers results in each boiler having a capacity of 502,000 lb/hr to also support the n-1 condition. Therefore, the plant is based on four 502,000 lb/hr boilers and four 34 MW STGs.

The n-2 boiler condition would provide the peak heating steam demand, but the electrical generation would be reduced. The heating steam would generate about 25 MW and the remaining 264,000 lb/hr would generate about 26.1 MW for a total of 51.1 MW gross, 46.0 MW net.

Although the regional plant would have sufficient boiler capacity to cover the heating steam demand in the n-2 boiler condition, the long distance heat transmission piping presents the opportunity for a single failure to stop delivery of the hot water for heating. On-site back-up at each facility can be provided by maintaining the existing boilers or a simpler approach

is to add new oil-fired package boilers or thermal storage tanks. The assumed basis is three 50 percent capacity boilers at each facility.

This alternative involves constructing a new major facility requiring PSD/NAA permitting. The CFBs will have SNCR for NOx control, limestone injection to the fluidized-bed for $SO_2$ control, and baghouses for particulate control. The combustion efficiency via state-of-the-art controls will provide the basis for CO and VOC emissions. The emission rates will be similar to the Alternative 5 new plants at FWA and EAFB. The back-up boilers at each facility would involve minor permitting because of the retirement of existing coal-fired boilers.

The generators for the STGs would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability could be incorporated in the design of the new boilers. Burners for fuel oil or natural gas and appropriate combustion controls and burner management systems would be required. An inert material such as sand would be required in the bed to allow the CFBs to maintain their heat transfer characteristics with either fuel oil or natural gas.

The general scope of this alternative includes a new standalone plant consisting of four CFBs each with SNCR and baghouses for emission controls, four STGs, air-cooled condensers, coal handling, limestone handling, ammonia storage and transfer, ash handling, balance of plant systems, building, two mile rail spur extension, and substation. New back-up boilers for heating at FWA and EAFB are included.

Evaluation of this option includes the capital cost investment for the long distance heat transmission pipeline and the new plant, paying a wheeling charge to GVEA, and O&M costs. The purchase of electricity from GVEA for the facilities being served should be minimal since the plant can provide the peak demand in the n-1 condition. There could be a need for the purchase electricity from GVEA by the facilities served if the n-2 boiler condition occurs at times of high demand. The development of this option has not considered any modifications necessary to the utilidor systems at FWA and EAFB to deliver heat when provided with hot water from the long-distance heat transmission system.

Consideration of the current use of steam for the installation's heat distribution might result in steam being the more appropriate long-distance transmission medium if the installation's distribution systems are not converted to hot water.

This alternative has the following advantage(s):

- new plant to meet heat and electrical needs of FWA and EAFB
- shutdown and demolition of existing CHPPs
- economy of scale
- elimination of emissions in the Fairbanks CO management/NAA
- improvement in fuel efficiency
- more efficient staffing and operations and maintenance.

This alternative has the following disadvantage(s):

- capital cost
- cost of heat transmission system
- reliance by FWA on importing heat from the regional plant (Implied need for backup heat plants and/or heat storage)
- reliance on GVEA transmission system to deliver power to three of the four installations
- potential vulnerability of heat transmission system.

*Alternative 4: Oil-Fired CHPP with Long-Distance Heat Transmission (Estimated Capital Cost—$302,939,000)*

This option will be based on meeting the peak electrical demands for all the facilities; FWA, EAFB, FGA (including the CRTC feed), and GMD; and the peak heating demands for FWA and EAFB using oil (DFA or naphtha) in a CT cogeneration configuration (CT with HRSG providing steam directly for heating demands). A specific location has not been selected for this analysis, but preferable attributes would include being either near the existing fuel oil line from the North Pole area refineries to EAFB or where a supply line can be easily provided, transmission lines in close proximity, having available water, allowing a relatively direct routing of the heat transmission line, and outside the Fairbanks area CO management/NAA. Similar to the other Alternatives, it is assumed the plant location is at EAFB and the design and cost are the same regardless of location. The long distance heat transmission piping is assumed to be 25 miles in length to allow for a less than direct routing from the plant to FWA and EAFB. The sizing basis will consider the individual electric peaks and heating peaks being concurrent. The sizing basis also allows 5 percent of the gross

generation for auxiliary power and a 10 percent increase in the heat demand to cover losses associated with conversion to hot water for transmission and heat losses during transmission. Since most of the electrical demand would be FWA and EAFB, no allowance is included for transmission losses. The estimated peak electrical demand in 2028 is 91.0 MW, consisting of 36.3 MW for FWA, 29.7 MW for EAFB, 10.1 MW for FGA (includes CRTC) and 14.9 MW for GMD. FWA and EAFB will require approximately 740,000 lb/hr (355,300 and 317,200 plus 10 percent) of steam to meet the peak heating demand. Considering the auxiliary power, the plant will require a capacity of about 95.8 MW. Providing this based on four installed units with three operating units for the n-1 condition requires each CT to be about 32.0 MW with an HRSG delivering about 247,000 lb/hr of heating steam.

A potential configuration is a General Electric LM2500+ aeroderivative CT with a duct-fired HRSG (HRSG) providing steam at 115 psig/353 °F for conversion to hot water. A combined cycle configuration was considered, but the quantity of heat required was excessive for the required power generation. The LM2500+ generates 33.2 MW at the annual average ambient temperature of 26 °F. While there are other potential CTs and configurations available, the GE LM2500+/HRSG configuration has been used here as a basis because it is representative and performance and cost information is readily available. The multiple units provide good operating flexibility over the load range.

Using a common header to supply the heating steam should result in good reliability. However, the loss of a CT means the loss of the heat source for its HRSG. The loss of another HRSG would create an n-2 HRSG condition even though only one HRSG had failed. Fresh air firing of the HRSG could be provided, but complete isolation of the CT to allow maintenance while operating an HRSG is a potential safety issue. An alternative solution is to provide additional duct burning to allow an increase in steam production to have two HRSGs supply the peak steam demand in the n-2 HRSG condition. Since the production of 247,000 lb/hr from an HRSG already requires significant duct-firing this is not considered a good solution. A more practical solution appears to be the inclusion of an auxiliary boiler with the capability of providing 247,000 lb/hr of 115 psig/353 °F steam to improve the reliability of providing steam for heating. However, the long distance heat transmission piping presents the opportunity for a single failure to stop delivery of the hot water for heating and locating oil-fired back-up

boilers at FWA and EAFB is a better solution. The assumed basis is three 50 percent capacity boilers at each facility.

This alternative involves constructing a new major facility requiring PSD/NAA permitting. NOx emission controls consists of water injection in conjunction with SCR. The $SO_2$ emissions will be a function of the sulfur level in the fuel oil. Ultra-low sulfur fuel oils are not readily available in the Fairbanks area, but the low sulfur fuels available should result in acceptable $SO_2$ emissions. CO and VOCs will be reduced via high combustion efficiency and oxidation catalyst. Formaldehyde is the primary concern for HAPs and could equal the total HAPs from the coal-fired alternatives. In summary, overall emissions should be as low as the best coal-fired alternative and probably better. The back-up boilers at each facility would involve minor permitting because of the retirement of existing coal-fired boilers.

The generators for the CTs would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability for the CTs and duct-firing of the HRSGs would require natural gas. Dual fuel capability with fuel oil and natural gas are relatively common for CTs and HRSGs and involve different combustors and burners respectively. Natural gas would result in lower emissions and reduced maintenance compared to fuel oil.

The general scope of this alternative includes a new standalone plant consisting of four CTs, four single-pressure HRSGs with duct firing, SCRs, CO catalyst, oil receiving, storage, and transfer; balance of plant systems, building, and substation. New back-up boilers for heating at FWA and EAFB are included.

Evaluation of this option includes the capital cost investment for the long distance heat transmission pipeline and the new plant, paying a wheeling charge to GVEA, and O&M costs. The purchase of electricity from GVEA should be minimal since the plant can provide the peak demand in the n-1 condition. The development of this option has not considered any modifications necessary to the utilidor systems at FWA and EAFB to deliver heat when provided with hot water from the long-distance heat transmission system.

This alternative has the following advantage(s):

- new plant to meet heat and electrical needs of FWA and EAFB
- shutdown and demolition of existing CHPPs
- economy of scale
- elimination of emissions in the Fairbanks CO management/NAA
- improvement in fuel efficiency
- more efficient staffing and operations and maintenance.

This alternative has the following disadvantage(s):

- capital cost
- cost of heat transmission system
- reliance by FWA on importing heat from the regional plant (Implied need for backup heat plants and/or heat storage)
- reliance on GVEA transmission system to deliver power to three of the four installations
- potential vulnerability of heat transmission system.

## Installation-Specific Solutions

### Retain Current Plant (Repair and/or Upgrade)

*Repair: No Added Capacity, Additional Power from Local Utility To Meet Future Demands*

This alternative is based on performing the necessary repair and maintenance on the existing equipment to allow continued operation for the study period. The current plants generally have sufficient capacity to satisfy the projected growth in heating demand. Additional power will be required during the study period and will be obtained from the local utility once the plant capacity is exceeded.

*Repair and Upgrade: Added Capacity To Meet Future Demands (Expand with Current Technology)*

The existing equipment will be repaired and maintained to allow continued operation. The plant capacity will be expanded by the addition of similar equipment to meet the growth. The installed boiler capacity is sufficient to support additional steam turbine capacity. Therefore, the upgrade would involve additional STG capacity. However, additional STG capacity removes a “bottleneck,” allowing higher coal consumption. There are many factors in determining the emission controls that could be required

by the removal of a bottleneck, but it is likely that a significant reduction in emission rates would be required.

*Repair: Electricity Produced by "Following the Heat Curve," Balance of Power from Local Utility*

This alternative involves the same equipment as the first alternative with a different operating approach, purchase of all electricity beyond that produced by following the heat curve. No steam would be produced only to generate electricity. This is the most fuel-efficient operating mode.

*Upgrade Coal-Fired Boilers and STGs with New CFBs and STG*

The existing boilers would be replaced with CFB units of additional capacity. New turbines would be added to take advantage of the available capacity. The existing STGs could continue in use with typical maintenance.

### New Plant

*CFBs for Coal (All Alternatives Can Be Gas or Oil Capable)*

New CFB units offer the ability to produce low emissions with coal in a relatively economical manner and allow burning of lower quality coals with proper design considerations.

*Oil- or Gas-Fired CTs with HRSGs for Heat and/or Power (Dual Fuel Capable)*

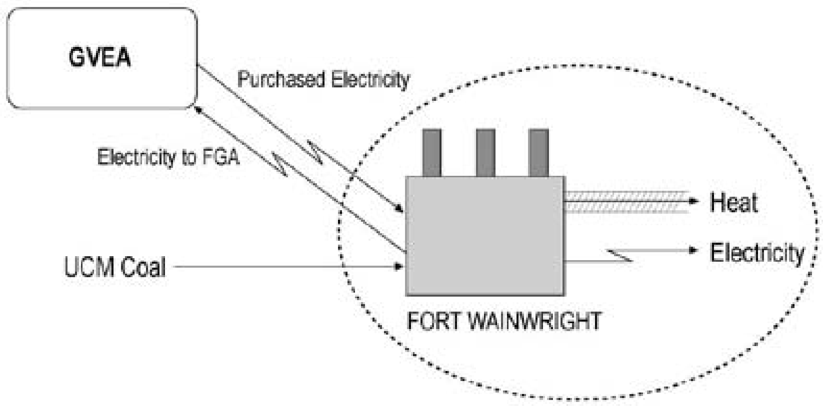
A CT with an HRSG on the exhaust to produce steam to drive an STG is a "combined cycle." This is a highly efficient thermal cycle. Some variations are generation of heating steam directly from the HRSG (no STG) and use of one or more of the existing STGs. The applicability of the variations depends on the ratio of electricity to heat over the duration of the study.

### FWA Alternatives Definition

The following alternatives have been developed for more detailed life-cycle cost evaluation. (Figure 23 for a schematic of the alternatives.) Appendix C includes the summary estimates for each of the alternatives and the basis of the estimates.

*Alternative 1: Repair: No Added Capacity (Estimated Capital Cost—$0)*

This option, by definition, makes use of the existing equipment. The costs of routine and major maintenance are included in the operating costs. Repairs are made to the CHPP to obtain original performance to the extent possible, but no capital investments are made in new or upgraded equipment.




**FWA Alternatives:**

1. **Repair and continue to operate existing CHPP:**
   - Operate CHPP, recognizing aging plant and need for increased maintenance
   - Heat needs met by CHPP
   - Electrical load growth from GVEA
2. **Repair and continue to operate existing CHPP, install additional steam turbine generators to take advantage of existing boiler capacity:**
   - Similar to Alternative 1 and install additional STGs
   - Heat needs met by CHPP
   - Maximizes onsite electricity generation / maximizes coal consumption / minimizes electricity purchases
   - Need to retrofit emissions controls - SCR for $NO_X$, offsets for CO, dry scrubber for $SO_2$
3. **Alternative 1 with operation to "follow the heat curve:"**
   - Maximizes fuel efficiency / Minimizes coal consumption
   - Minimizes onsite electrical generation / maximizes electricity purchases from GVEA
5. **Replace existing CHPP with new circulating fluidized-bed boilers**
   - New cleaner technology / reduced emissions
   - Self-sufficiency for heat and electricity
   - Improved fuel efficiency
   - Improved operational efficiency
   - Within the Fairbanks non-attainment area for CO
6. **Replace existing CHPP with new combustion turbines and heat recovery steam generators**
   - Oil as fuel (expensive fuel on $/MMBtu basis)
   - Conversion to natural gas, if available
   - High fuel efficiency
   - Improved operational efficiency
   - Reduced emissions from improved emissions control
   - Self-sufficiency for heat and electricity
   - Within the Fairbanks non-attainment area for CO

*FIGURE 18-2*
**INSTALLATION SPECIFIC ALTERNATIVES**
FORT WAINWRIGHT
**CH2MHILL**

Figure 23. Alternatives developed for more detailed life-cycle cost evaluation.

The six boilers have a nameplate capacity rating of 150,000 lb/hr each. Currently, the boilers are limited to approximately 90,000 lb/hr due to emission (particulate) and reliability concerns. Assuming the current repairs and baghouse addition restore full capability, this equates to 900,000 lb/hr installed capacity and 750,000 lb/hr under the “n-1” operating condition.

Installed steam turbine-generator (STG) capacity consists of 20 MW from one 5 MW backpressure turbine (Unit 1) and three 5 MW condensing turbines (Units 3, 4, & 5). Unit 2 has been inoperative for years and is not considered in this option. The STGs are capable of achieving nameplate capacity, but there is a preference for use of the three condensing turbines to the maximum extent possible before operating the backpressure turbine. The installed capacity is considered gross output. The CHPP auxiliaries are estimated to be 15 percent of the gross output. Therefore, the 20 MW nameplate capacity represents 17 MW net available to meet demand.

The current heating steam demand is a peak of 290,000 lb/hr and average of 173,600 lb/hr. The estimated heating steam demands at the end of the study period are 355,300 lb/hr peak and an average of 212,700 lb/hr. The generation of electricity at the installed STG capacity concurrent with the peak heating demand requires a maximum steam flow of approximately 468,600 lb/hr (355,300 lb/hr for heating plus an additional 113,300 lb/hr for power generation). This is calculated based on a theoretical steam rate of 26.25 lb/kWh with internal turbine efficiency of 78 percent for “extraction steam” (from the throttle to extraction point) and 7.69 lb/kWh and 64 percent for “condensing steam” (throttle to condenser).

The installed boiler capacity is sufficient even in a “n-2” operating condition or in the n-1 condition at a reduced capacity of approximately 95,000 lb/hr/boiler. At the end of the study period, the boilers will be 75 years old. As a result, it is likely that they will not always perform at full capacity or with “as new” reliability. Even so, it appears sufficient boiler capacity for steam can be provided via a repair program.

The current peak electrical demand is 20.4 MW. The peak electrical demand is expected to be 36.3 MW by the end of the study period. The electricity required beyond the plant’s capability will have to be imported, presumably a purchase from GVEA. The plant is interconnected with GVEA and has the capability to receive up to 12.5 MVA [10 MW at 80 percent

power factor(pf)] via a 7.5 MVA tie and the 5 MVA “back-door” tie. Since the plant is capable of generating 15 MW (delivering 12.75 MW) in the n-1 turbine condition, the interconnections with GVEA will need to be upgraded to at least 29.4 MVA (23.55 MW at 80 percent pf) by the end of the study period.

There are no permitting requirements for this alternative. The emission rates remain the same for each ton of coal burned. The degree or timing of Hg removal requirements is uncertain at this point. However, this will apply to all coal burning facilities (even if no modifications are made) and it is assumed that the impact will be the same on all coal-burning alternatives.

Providing dual fuel capability would involve retrofitting fuel oil or natural gas burners to the boilers. The new burners would require new combustion controls and burner management systems. Fuel oil would also involve unloading, storage, and transfer systems. Natural gas, if pipeline gas became available, would involve piping the supply to the boilers. Liquefied natural gas (LNG) would involve storage and vaporization facilities. A detailed analysis of the boilers would be necessary to determine if firing fuel oil or natural gas would result in a derating of the boilers.

Key factors in the evaluation of this option are reduced up-front capital investment, relatively high maintenance expenses, and increased purchases of electricity from GVEA. The no capital improvement approach will require continued maintenance of an old power plant; it is expected that this will be at a significantly higher cost than typically associated with a power plant. There are some on-going and planned repair (boiler refurbishment) and upgrade (air-cooled condenser) projects that have been funded and need to be completed as part of this option. The plant personnel have also indicated there are a number of projects that need to be done in the near-term that are currently not funded. Many of the desired projects are repair or replacement activities that are relatively small individual projects, but as a whole represent a need for continued significant financial investment in the plant. Higher levels of maintenance funding should allow implementation of many of the smaller projects during the next few years. The replacement of the current distributed control system (DCS) with a PC-based system incorporating more control functions is a key project that should be funded in the next few years. A previous study recommended the addition of backup power generation and this will be included for all the Alternatives at Fort Wainwright.

Significant operating efficiency improvements (labor, fuel, etc.) would not be anticipated.

This alternative has the following advantage(s):

- no capital investment
- continue under existing environmental permits
- heat needs met by CHPP
- recapture of recent investments in repairs and baghouse.

This alternative has the following disadvantage(s):

- continuing dependence on aging CHPP
- increased operations and maintenance requirements over time
- exposure to significant outages from equipment failure
- need for FWA to purchase electricity in all years.

*Alternative 2: Repair and Upgrade with New STG (Estimated Capital Cost—$110,465,000)*

The boiler portion of the plant will require repair, but, as presented above for Alternative 1, should not require upgrading to meet the heating demand. However, the available steam supply is sufficient to support the installation of up to 45 MW gross of additional STG capacity. The estimated peak heating steam demand in 2029 is 355,300 lb/hr, which provides delivery of approximately 9.0 MW (10.6 MW gross) of power generation from the steam produced to meet the heating load (extraction).

Assuming the nameplate boiler capacity is restored, there would be 544,700 lb/hr (900,000 lb/hr total capacity less the 355,300 lb/hr of peak heating steam demand) of steam available for power generation (n-1 condition would have 394,700 lb/hr). The available steam is estimated to provide 38.4 MW (45.2 MW gross) of additional generation from condensing operation of the STGs. This condenser steam generation, in conjunction with the 9.0 MW provided by the extraction steam generation, results in the steam capability to deliver 47.4 MW (55.8 MW gross), assuming there is sufficient STG capacity, exceeding the estimated 2028 peak demand of 36.3 MW. Meeting the estimated peak demand in 2028 requires a gross capacity of 42.7 MW. The steam flow associated with providing the peak heating demand and 36.3 MW (42.7 MW gross) is 753,040 lb/hr.

The CHPP generating capability would have to be upgraded through the addition of approximately 24 MW to meet the estimated peak. Because

this addition would more than double the installed capacity, multiple units for the added capacity are considered appropriate.

Replacement of the Unit 1 STG has been suggested as desirable by FWA CHPP personnel. The Unit 1 STG is a backpressure unit discharging to the 10-psig steam header. Reductions in the 10-psig steam demands have affected its operation, relegating it to being the least preferred machine. Its replacement retires 5 MW and increases the new capacity requirement to 29 MW. It is also logical to consider the space occupied by the inoperable Unit 2 STG.

Use of the Unit 1 and Unit 2 areas has the advantage of being in close proximity to the interfaces with the existing plant services (steam headers, cooling water, electrical, etc.). The footprint for a modern 15 MW STG is slightly larger than the Unit 2 footprint, but there is sufficient space in the area to implement a modern 15 MW machine. The Unit 1 footprint is larger than that of Unit 2 and can accommodate the addition of a 15 MW unit. The interconnection with GVEA will need to allow delivery of 18.75 MVA (15 MW at 80 percent pf) to meet the peak demand in the n-1 turbine condition.

This alternative requires permitting. The addition of STG capacity removes a "bottleneck," allowing the facility to operate at a higher coal consumption rate. This could be a difficult alternative to permit. The emission controls required to obtain a permit depend on many factors, including the difference between past actual emissions and future potential emissions, the technologies available at the time of the permit, and any limits on operations the facility is willing to accept.

The major problem is an increase in CO emissions within the Fairbanks management/NAA. Currently, there is no "add-on" technology for CO reductions in a coal burning plant, Best Available Control Technology (BACT) is modern combustion controls. CO offsets, comparable reductions in CO emissions from other sources in the area, are required.

It is assumed that NOx reduction will require the use of selective catalytic reduction (SCR) and $SO_2$ will be reduced with a dry scrubber using lime as a reagent. These control technologies will reduce total emissions even though the coal consumption increases. The addition of emission controls will be a difficult retrofit due to available space and the need to have the proper temperature window for the SCR catalyst and to have the dry

scrubber upstream of the baghouse. The volume of the flue gas to the baghouse will be reduced because of the lower temperature after the dry scrubber, potentially allowing a downsizing of the baghouse to gain space for the other controls. No other air emission controls are expected to be required because of implementing this alternative.

Providing dual fuel capability would involve retrofitting fuel oil or natural gas burners to the boilers. The new burners would require new combustion controls and burner management systems. Fuel oil would also involve unloading, storage, and transfer systems. Natural gas, if pipeline gas became available, would involve piping the supply to the boilers. Liquefied natural gas (LNG) would involve storage and vaporization facilities. A detailed analysis of the boilers would be necessary to determine if firing fuel oil or natural gas would result in a derating of the boilers.

The general scope for this alternative includes removal of STG Units 1 & 2 with their associated pedestals and foundations, replacement STGs with associated pedestals and foundations, new air-cooled condensers, addition of associated electrical equipment, new dry scrubbers, and new SCRs. This is viewed as a difficult retrofit with loss of labor productivity because of tight working areas within an operating plant, difficult positioning of construction equipment, and remote laydown area resulting in double handling of materials.

Evaluation of this alternative includes the new capital investment for the difficult retrofit of additional electrical generation equipment (STGs, condensers, CW pumps, switchgear, etc.), retrofit of emission controls, the relatively high maintenance costs for the remainder of the plant, the consumption of additional coal for power generation, and the purchase of electricity from GVEA.

There is also more risk in meeting the maximum demands under this alternative than for Alternative 1 because the maximum electrical generation in conjunction with the maximum heating demand requires operation of all boilers at almost 90 percent of nameplate capacity (demanding service for 75 year old boilers and auxiliaries). The n-1 boiler condition at full nameplate capacity provides the peak heating steam demand plus about 36.8 MW (net).

A subset of this alternative would be to install only one new STG and import the balance of the power needs to reduce the dependency under peak

conditions on the 75-year-old boilers and auxiliaries. The GVEA tie would then need to be 36 MVA (29 MW at 80 percent pf) to assure the peak electrical demand can be met in the n-1 turbine condition.

Significant operating efficiency improvements (labor, fuel, etc.) would not be anticipated.

This alternative has the following advantage(s):

- heat needs met by CHPP
- ability to meet installation heat and electricity needs after 2011
- maximizes onsite electricity generation
- maximizes coal consumption
- minimizes electricity purchases.

This alternative has the following disadvantage(s):

- retrofit of emissions controls for NOx, $SO_2$, CO, VOCs (difficult, expensive) or obtain offsets (for CO)
- relatively high capital cost, minimal improvement in operations
- continuing dependence on aging CHPP
- increased operations and maintenance requirements over time
- exposure to significant outages from equipment failure.

*Alternative 3: Repair: Electricity Produced by Following the Heating Demand (Estimated Capital Cost—$0)*

From an equipment perspective, this is the same as Alternative 1. (The costs of routine and major maintenance are included in the operating costs.) The difference is in how the plant is operated. This type of operation is sometimes called “following the heat curve” and is a fuel-efficient operating mode. It takes advantage of the electricity that is a “by-product” of using a steam turbine in place of a pressure reducing valve to go from the boiler pressure (nominally 400 psig) to the heating system distribution pressure (nominally 100 psig) in this case.

The use of condensing steam turbines at FWA (Units 3-5) results in the need to produce some steam flow and subsequent electrical generation beyond the “heat curve” (extraction) requirements because of cooling requirements for the lower pressure stages of the turbine downstream from extraction point to the condenser. This cooling flow produces additional power by going through all stages of the turbine to the condenser. The cooling steam is estimated to be 10 percent of the throttle flow to the tur-

bine. The throttle flow at the peak heating demand is estimated to be 394,800 lb/hr, 355,300 lb/hr for heating demand and 39,500 lb/hr for turbine cooling. The additional flow for cooling generates an extra 3.3 MW with all three condensing turbines in service, about 2.8 MW net. Since the peak heating steam demand provides 9.0 MW (10.6 MW gross) and the additional cooling flow 2.8 MW, 11.8 MW is the maximum available power when following the heat curve.

At the end of the study period, the interconnection with GVEA will need to be 30.6 MVA (24.5 MW at 80 percent pf) to cover the estimated peak. This would require two 12/16/20 MVA transformers. The n-1 turbine condition does not influence the interconnection size since the maximum generation can be provided in the n-1 condition. The maximum steam demand is 394,800 lb/hr, significantly lower than the n-3 boiler capacity.

There are no permitting requirements for this alternative. Emission rates remain the same per ton of coal consumed and coal consumption is the lowest for Alternatives involving the existing plant.

Providing dual fuel capability would involve retrofitting fuel oil or natural gas burners to the boilers. The new burners would require new combustion controls and burner management systems. Fuel oil would also involve unloading, storage, and transfer systems. Natural gas, if pipeline gas became available, would involve piping the supply to the boilers. Liquefied natural gas (LNG) would involve storage and vaporization facilities. A detailed analysis of the boilers would be necessary to determine if firing fuel oil or natural gas would result in a derating of the boilers.

The key factors in evaluating this option are the same as Alternative 1 with a larger amount of power being purchased from GVEA. It is necessary to account for the additional fuel associated with producing the condenser steam, but this will be much less than in Alternative 1. Improved fuel efficiency will result.

This alternative has the following advantage(s):

- no capital investment
- continue under existing environmental permits
- reduced onsite coal use
- maximizes fuel efficiency
- minimizes coal consumption.

This alternative has the following disadvantage(s):

- continuing dependence on aging CHPP
- increased operations and maintenance requirements over time
- exposure to significant outages from equipment failure
- maximize electricity purchases, increased costs from purchased power.

*Alternative 4: Upgrade with New CFBs and Additional STG*

This option is not considered for FWA. Considering the recent and on-going repairs to the CHPP and its boilers, there is no incentive for a substantial capital investment in new boilers that will not provide significant improvements in plant performance.

Boiler efficiency is primarily a function of the fuel. New boilers using the same coal and providing the same heat transfer will likely provide a small improvement in boiler efficiency, perhaps 2 or 3 percent, which represents an annual saving on the order of $200,000 to $300,000. This would justify a capital investment on the order of $2,000,000 to $3,000,000. New boilers and additional steam turbines would cost many times this amount.

*Alternative 5: New Plant Using CFBs (Estimated Capital Cost—$200,665,000)*

A new plant can be designed using CFBs with a more efficient steam cycle for the production of electricity. The current plant using 400 psig/650 °F steam at the turbine throttle (425 psig/660 °F steam at the boiler outlet) has an ideal Rankine cycle efficiency of about 35 percent (typical actual efficiency would be up to about 25 percent). A plant using 850 psig/900 °F steam at the turbine throttle has an ideal Rankine cycle efficiency of about 40 percent, a 5 percentage point improvement.

The plant is sized to concurrently meet the projected peak heating demand (355,300 lb/hr) and generate the projected electrical peak demand (36.3 MW) using condensing STGs rated for 850 psig/900 °F steam at the throttle with a 100 psig extraction point to provide heating steam and allowing 12 percent of the gross generation for auxiliary power. The projected electrical peak of 36.3 MW requires generation of 41.2 MW with auxiliary power of 12 percent. Considering the peak heating steam demand and allowing for the feedwater heating typical of a cycle using these steam conditions, the throttle flow to generate 41.2 MW is approximately 690,000 lb/hr. Using four boilers requires a capacity of 172,500 lb/hr each. Three boilers could be provided and the heating steam plus some part of the electrical demand can be satisfied in the n-1 boiler condition.

However, the current plant has significant redundancy for steam generation and four boilers for this option would allow the estimated peak heating demand to be satisfied in the n-2 boiler condition. Therefore, the use of four boilers is the basis for this option. STGs are generally more reliable than boilers and back-up or replacement of electricity can be provided via other means (such as the GVEA interconnection and backup generators). Providing the generating capacity in three STGs requires nominal ratings of 15 MW each and is the basis for this option.

Four boilers in the n-1 condition provide 517,500 lb/hr of steam. The estimated generation under this condition is 29 MW gross, 26 MW net. This is 10 MW short of the peak electrical demand. The n-1 turbine condition is larger, about 12 MW short of the peak electrical demand, and required electricity under that condition should be purchased from GVEA. The GVEA interconnection needs to have a capacity of 15 MVA (12 MW at 80 percent pf) to address this condition.

The n-2 boiler condition provides the estimated peak heating steam, but since it requires essentially all the available steam it has a significant impact on the power generation. The estimated generation is 14.9 MW gross (13.1 MW net). Therefore, meeting the peak electrical demand requires an additional 23.2 MW. The additional power can be provided by a combination of the GVEA interconnection and backup generators. The GVEA interconnection should be its standard 20-MVA configuration to cover the n-1 turbine condition, minimizing the use of backup generators under normal maintenance conditions. The balance can be provided by adding backup generators based on a previous recommendation discussed in Section 19 under Planned Near-Term Investments. Therefore, the new plant will consist of four 180,000-lb/hr CFBs and three nominal 15 MW steam turbines.

Emission controls include selective non-catalytic reduction for NOx, use of limestone for in-bed $SO_2$ reduction, and a baghouse for PM removal. It is expected that improved combustion efficiency will result in lower CO and VOC emissions. The emission of HAPs should also be lower than alternatives involving the existing facility.

The generators for the steam turbines would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability could be incorporated in the design of the new boilers. Burners for fuel oil or natural gas and appropriate combustion controls and burner management systems would be required. An inert material such as sand would be required in the bed to allow the CFBs to maintain their heat transfer characteristics with either fuel oil or natural gas.

It is assumed that the area southwest of the current plant can be used for a new plant. The area would be close to the existing coal receiving, cooling pond, and switchyard. The use of this area would allow relatively easy interfacing with the utilidor system.

The general scope of this alternative includes a new standalone plant consisting of four CFBs each with SNCR and baghouses for emission controls, three STGs, air-cooled condensers, coal handling, limestone handling, ash handling, balance of plant systems, building, rail spur extension, and substation.

Evaluation of this option includes the significant capital investment associated with a new plant, reduced O&M compared to the existing plant, a more efficient cycle, and a similar number of operating personnel. There will be a need to purchase electricity from GVEA at times of high demand if equipment is out of service. The CFBs also provide an opportunity to use a lower quality coal that could result in a discount compared to the current coal price.

This alternative has the following advantage(s):

- new cleaner technology, reduced emissions
- self-sufficiency for heat and electricity
- improved fuel efficiency
- improved operational efficiency
- allows abandonment (and demolition) of existing CHPP
- uses a “secure” fuel.

This alternative has the following disadvantage(s):

- capital investment required
- within the Fairbanks management/NAA for CO (although total emissions are reduced).

*Alternative 6: CT Cogeneration (HRSG for Heat): Liquid Fuel (Estimated Capital Cost—$99,514,000)*

The projected 2028 peak electrical demand, 36.3 MW, can be satisfied by CTs. The CTs will provide exhaust heat that can be recovered to produce steam in an HRSG. This steam can be used to either generate additional electricity in a steam turbine (a combined cycle) or directly as heating steam (CT cogeneration). The relatively high ratio of peak heating demand to peak electricity demand favors using the HRSG steam directly, the CT cogeneration approach. Auxiliary power for this type of plant is conservatively estimated to be 5 percent of gross output, resulting in a need to generate a total of about 38.1 MW. The peak electrical demand can be more than satisfied by two GE LM2500+ CTs at all ambient temperatures. Aeroderivative-type CTs such as the LM 2500+ require heating of the inlet air at low ambient temperature conditions to avoid icing problems; resulting in a relatively small variation in full load output compared to industrial-type CTs. Full load output for one LM2500+ ranges from about 26 MW to about 31.5 MW, depending on ambient conditions. Each HRSG would need to provide approximately 180,000 lb/hr to the heating system to meet the estimated peak heating steam demand. The unfired condition would provide about 100,000 lb/hr at average ambient conditions. It is generally feasible to double the HRSG output by duct firing without substantial impact on the HRSG design. Therefore, this combination appears to be a reasonable match for the peak demands. The installation of three CT/HRSGs units will be examined to address the n-1 conditions. While there are other potential gas turbines for the application, the LM2500+ has been used as a basis since it is representative and performance and cost information is readily available.

The CT n-1 condition impacts the ability to provide both heat and electricity at high demands. The loss of a CT essentially creates an n-1 condition for the HRSGs. The loss of another HRSG would create an n-2 HRSG condition even though only one HRSG had failed. It is possible to use additional fuel oil to replace the heat input from the CT exhaust with the addition of a fresh air fan to the HRSG, but complete isolation of the CT to allow maintenance while operating its associated HRSG is a potential operational safety issue. Since the production of over about 200,000 lb/hr of steam in one HRSG would involve a more expensive HRSG design, production of 355,300lb/hr in a single HRSG is not considered feasible. The most practical solution appears to be the inclusion of an oil-fired package boiler with the capability of providing 180,000 lb/hr of steam at the heating system conditions to improve the reliability of providing back-up heat-

ing steam. The CT n-1 condition has the capability to meet the peak electrical demand. The new plant basis is three GE LM2500+ CTs, three HRSGs designed to provide 180,000 lb/hr each, and an oil-fired 180,000 lb/hr auxiliary boiler. Since the n-1 CT condition can meet the maximum electrical demand, the existing GVEA interconnection capacity is sufficient.

The net emissions from shutting down of the existing boilers allows the use of a minor construction permit. NOx emission controls consists of water or steam injection in conjunction with SCR. The $SO_2$ emissions will be a function of the sulfur level in the fuel oil. Ultra-low sulfur fuel oils are not readily available in the Fairbanks area, but the low sulfur fuels available result in lower $SO_2$ emissions than the current plant. CO and VOCs will be reduced via high combustion efficiency and oxidation catalyst. Formaldehyde is the primary concern for HAPs and could equal the total HAPs from the coal-fired alternatives. In summary, overall emissions should be as low as the best coal-fired alternative and probably better.

The generators for the CTs would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability for the CTs and duct-firing of the HRSGs would require natural gas. Dual fuel capability with fuel oil and natural gas is relatively common for CTs and HRSGs and involve different combustors and burners respectively. Natural gas would result in lower emissions and reduced maintenance compared to fuel oil.

The area southwest of the current plant would be used for the CT cogeneration plant. Oil delivery, transfer, and storage facilities are included for the new plant. There could be operating conditions, such as peak heating steam demand with less than peak electrical demand, that result in excess generation to meet the heating demand. Provisions to provide electricity to GVEA would be beneficial and need to be considered.

The general scope of this alternative includes a new standalone plant consisting of three CTs, three single-pressure HRSGs with duct firing, SCRs, CO catalyst, oil receiving, storage, and transfer; balance of plant systems, package boiler, building, and substation.

The evaluation of this option includes the capital investment, consumption of liquid fuel, and O&M requirements. The firing of the HRSGs will provide some flexibility to meet heating loads independent of electrical demands. However, CT efficiency of operation at part loads is generally much lower than at full load. Also, it will be necessary to follow electrical demand unless GVEA is willing to purchase electricity at times.

This alternative has the following advantage(s):

- lower capital cost
- new clean technology, reduced emissions
- self-sufficiency for heat and electricity
- high fuel efficiency
- improved operational efficiency
- allows abandonment (and demolition) of existing CHPP
- conversion to natural gas, if available
- improved operational efficiency
- reduced emissions from improved emissions control (including ability to greatly reduce CO).

This alternative has the following disadvantage(s):

- expensive fuel, volatile prices, high fuel costs
- less secure fuel
- shorter economic life
- within the Fairbanks management/NAA for CO.

### EAFB Alternatives Definition

Figure 24 schematically depicts the alternatives at EAFB.

*Alternative 1: Repair: No Added Capacity (Estimated Capital Cost—$0)*

This option makes use of the existing equipment. The costs of routine and major maintenance are included in the operating costs. Repairs are made to the CHPP to obtain original performance as much as possible, but no capital investments are made in new or upgraded equipment.

The six boilers have a nameplate capacity rating of 120,000 lb/hr each. Currently, the boilers are limited to approximately 80,000 lb/hr due primarily to emission (particulate) concerns. Assuming the baghouse addition restores full capability, this equates to 720,000 lb/hr installed and 600,000 lb/hr under the “n-1” operating condition.

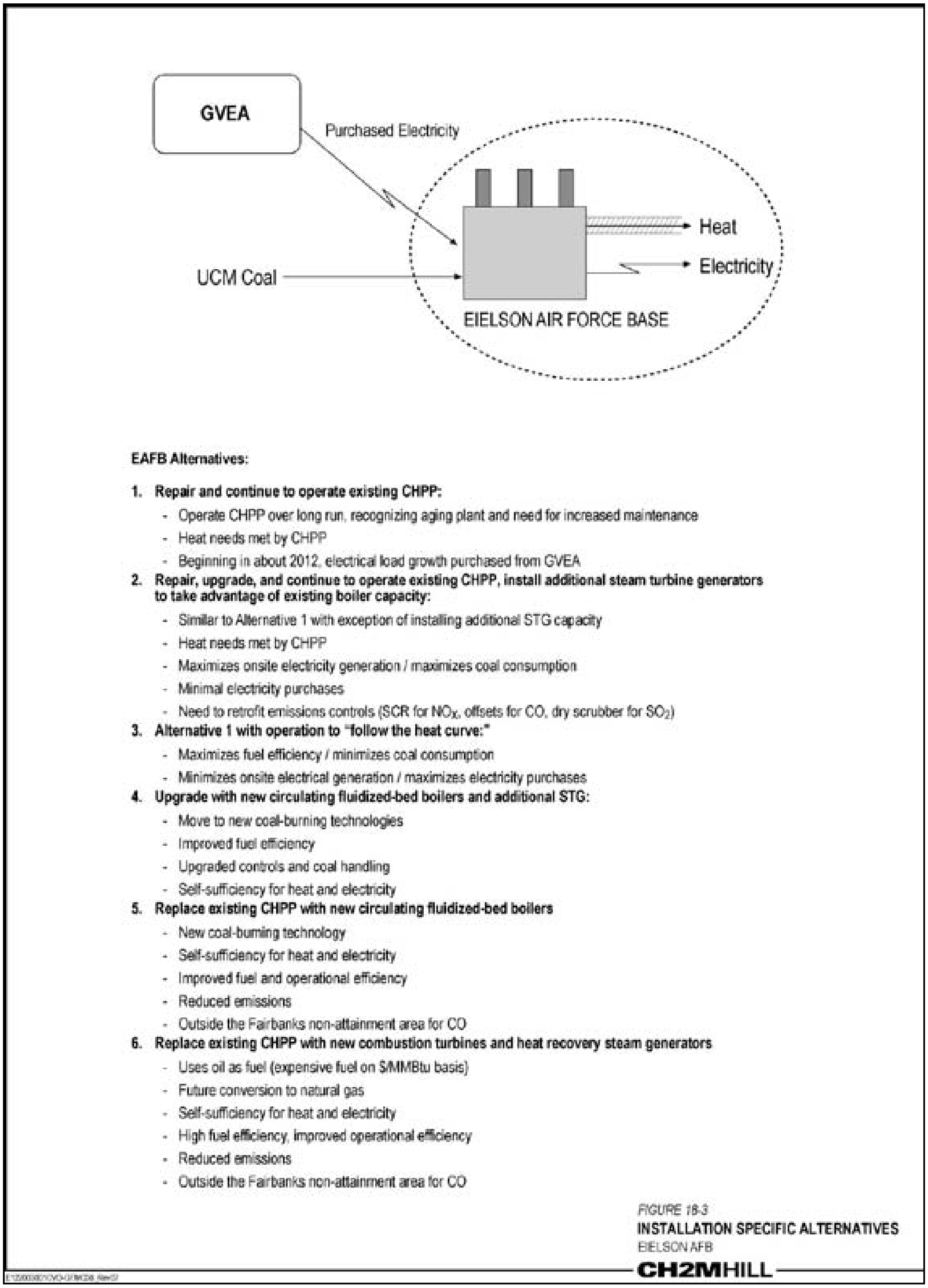



Figure 24. EAFB alternatives.

Installed STG capacity consists of 25 MW from one 10 MW condensing turbine (Unit 5), two 5 MW condensing turbines (Units 3 & 4), and two 2.5 MW condensing turbines (Units 1&2). The STGs are capable of achieving nameplate capacity, but there is a preference for use of the three larger

condensing turbines to the maximum extent possible. The installed capacity is considered gross output. The CHPP auxiliaries are estimated to be 15 percent of the gross output. Therefore, the 25 MW nameplate capacity represents 21.25 MW net available to meet demand with all STGs available, 12.75 MW with the largest STG not available (n-1).

There are also five oil-fired diesel electric generators with an installed capacity of about 8.5 MW (net). The installed diesels generators consists of a 2.5 MW unit with black start capability and four 1.5 MW units. The diesel generators are considered back-up capacity and as such, are not part of the generation during normal operations. Although operation is infrequent, periodic maintenance is required and the n-1 condition is considered. Therefore, the diesel generators represent 6 MW of firm back-up.

The current heating steam demand is a peak of 281,400 lb/hr and average of 119,600 lb/hr. The estimated heating steam demands at the end of the study period are 317,200 lb/hr peak and an average of 134,800 lb/hr. The generation of electricity at the installed STG capacity concurrent with the peak heating demand requires a maximum of approximately 505,200 lb/hr. This maximum is based on the 317,200 lb/hr of heating steam generating 9.4 MW gross and the 15.6 MW gross remaining installed STG capacity being provided by an additional 188,000 lb/hr of steam from the turbine throttle to the condenser (theoretical steam rate of 7.69 lb/kWh and estimated internal turbine efficiency of 64 percent).

The installed boiler capacity is sufficient in the n-1 operating condition, even at a reduced capacity of approximately 100,000 lb/hr/boiler. At the end of the study period, the boilers will be 75 years old. As a result, it is likely that they will not always perform at full capacity or with “as new” reliability. Even so, it appears sufficient boiler capacity for steam can be provided via a repair program.

The current peak electrical demand is 18.5 MW. The peak electrical demand is expected to be 29.7 MW by the end of the study period. The electricity required beyond the plant’s STG capability will have to provided by a combination of purchase from GVEA and diesel generation. The plant is interconnected with GVEA and currently has the capability to receive up to 12.5 MVA [10 MW at 80 percent power factor (pf)]. Since the plant is capable of generating 15 MW (delivering 12.75 MW) in the n-1 steam turbine condition plus 6 MW from the diesels, the interconnections with GVEA

will need to be upgraded slightly, to at least 13.6875 MVA (10.95 MW at 80 percent pf).

There are no permitting requirements for this alternative. The emission rates remain the same for each ton of coal burned. The degree or timing of Hg removal requirements is uncertain at this point. However, this will apply to all coal burning facilities (even if no modifications are made) and it is assumed that the impact will be the same on all coal-burning alternatives.

Providing dual fuel capability would involve retrofitting fuel oil or natural gas burners to the boilers. The new burners would require new combustion controls and burner management systems. Fuel oil would also involve unloading, storage, and transfer systems. Natural gas, if pipeline gas became available, would involve piping the supply to the boilers. LNG would involve storage and vaporization facilities. A detailed analysis of the boilers would be necessary to determine if firing fuel oil or natural gas would result in a derating of the boilers

Key factors in the evaluation of this option are no capital investment, relatively high maintenance expenses, and increased purchases of electricity from GVEA. The no capital improvement approach will require continued maintenance of an old power plant. It is expected that this will be at a significantly higher cost than typically associated with a power plant.

Significant operating efficiency improvements (labor, fuel, etc.) would not be anticipated.

This alternative has the following advantage(s):

- no capital investment
- continue under existing environmental permits
- heat needs met by CHPP
- recapture of recent investments in repairs and baghouse.

This alternative has the following disadvantage(s):

- continuing dependence on aging CHPP
- increased operations and maintenance requirements over time
- exposure to significant outages from equipment failure
- need to purchase electricity beginning 2012.

*Alternative 2: Repair and Upgrade (Estimated Capital Cost—$86,000,000)*

The boiler portion of the plant will require repair, but, as presented above for Alternative 1, should not require upgrading to meet the heating demand. However, the available steam supply is sufficient to support investigating the installation of additional STG capacity. The estimated peak heating steam demand in 2028 is 317,200 lb/hr, which provides delivery of approximately 8.0 MW (9.4 MW gross) of power generation from the steam produced to meet the heating load (extraction).

Assuming the nameplate boiler capacity is restored, there would be 402,800 lb/hr of steam available for power generation (n-1 condition would have 282,800 lb/hr). The available steam is estimated to provide the capability to provide up to 33.4 MW (28.4 MW net) of additional generation from condensing operation of the STGs. This "condenser" generation, in conjunction with the 8.0 MW provided by the "extraction" generation, results in the steam capability to deliver 36.4 MW (42.8 MW gross), 6.7 MW more than the estimated peak demand, assuming there is sufficient STG capacity. The estimated peak of 29.7 MW requires generation of 34.9 MW if steam turbines produce all the electricity. Since there is currently 25 MW of installed capacity, about 10 MW of additional STG capacity would allow the plant to meet its estimated electrical peak with internally generated electrical power from steam turbines. This would require approximately 624,500 lb/hr of steam if concurrent with the peak heating steam demand (317,200 lb/hr for heating and 307,300 lb/hr of condenser steam for additional power generation). The n-1 boiler condition in conjunction with the peak heating demand would provide 28 MW net. Considering the 6 MW of firm diesel capacity, the upgraded plant has the ability to provide 34 MW net generation in the n-1 boiler condition and 31 MW in the n-1 turbine condition.

The CHPP generating capability would have to be upgraded through the addition of a nominal 10 MW STG to meet the estimated peak electrical demand. There are a number of ways an addition can be approached. A single new steam turbine can be added as an extension of the building or replacement of Units 1 and 2 with either a single full size unit or two half-size units can be considered. Since there is no particular concern over the continued operation of Units 1 & 2, the addition via an extension of the building is considered as the basis.

The addition of a 10 MW steam turbine will require the extension of steam headers, circulating water, and other interfaces. The interconnection with

GVEA will need to allow delivery of 12.5 MVA (10 MW at 80 percent pf) to meet the peak demand in the n-1 turbine condition without the use of the back-up diesels.

This alternative requires permitting. The addition of STG capacity removes a “bottleneck,” allowing the facility to operate at a higher coal consumption rate. This could be a difficult alternative to permit. The emission controls required to obtain a permit depend on many factors, including the difference between past actual emissions and future potential emissions, the technologies available at the time of the permit, and any limits on operations the facility is willing to accept.

Currently, there is no “add-on” technology for CO reductions in a coal burning plant, BACT is modern combustion controls. CO offsets, comparable reductions in CO emissions from other sources in the area, are required.

It is assumed that NOx reduction will require the use of selective catalytic reduction (SCR) and $SO_2$ will be reduced with a dry scrubber. These control technologies will reduce total emissions even though the coal consumption increases. The addition of emission controls will be a difficult retrofit due available space and the need to have the proper temperature window for the SCR catalyst and the dry scrubber upstream of the baghouse. The volume of the flue gas to the baghouse will be reduced because of the lower temperature after the dry scrubber, potentially allowing a downsizing of the baghouse to gain space for the other controls. No other air emission controls are expected to be required because of implementing this alternative.

Providing dual fuel capability would involve retrofitting fuel oil or natural gas burners to the boilers. The new burners would require new combustion controls and burner management systems. Fuel oil would also involve unloading, storage, and transfer systems. Natural gas, if pipeline gas became available, would involve piping the supply to the boilers. LNG would involve storage and vaporization facilities. A detailed analysis of the boilers would be necessary to determine if firing fuel oil or natural gas would result in a derating of the boilers.

The general scope for this alternative includes the construction of a building extension, installation of a new 10 MW condensing STG with associated mat foundation, new air-cooled condenser, addition of associated

electrical equipment, new dry scrubbers, and new SCRs. This is viewed as a difficult retrofit with loss of labor productivity because of tight working areas within an operating plant, difficult positioning of construction equipment, and remote laydown area resulting in the double handling of materials.

Evaluation of this alternative includes the new capital investment for the retrofit of additional of electrical generation equipment (STG, condenser, CW pumps, switchgear, etc.), retrofit of emission controls, extension of the building, the relatively high maintenance costs for the remainder of the plant, the consumption of additional coal for power generation, and the purchase of electricity from GVEA.

There is somewhat more risk in meeting the maximum demands under this alternative than for Alternative 1 because using internal generation to satisfy the maximum electrical demand in conjunction with the maximum heating demand requires operation of all boilers at near 90 percent of nameplate capacity; demanding service for 75-year-old boilers and auxiliaries. The n-1 boiler condition at full nameplate capacity provides the peak steam demand plus about 28 MW net.

Significant operating efficiency improvements (labor, fuel, etc.) would not be anticipated.

This alternative has the following advantage(s):

- heat needs met by CHPP
- ability to meet installation heat and electricity needs
- maximizes onsite electricity generation
- maximizes coal consumption
- minimizes electricity purchases.

This alternative has the following disadvantage(s):

- retrofit of emissions controls for NOx, $SO_2$, CO, VOCs (difficult, expensive)
- relatively high capital cost, minimal improvement in operations
- continuing dependence on aging CHPP
- increased operations and maintenance requirements over time
- exposure to significant outages from equipment failure.

*Alternative 3: Repair: Electricity Produced by Following the Heating Demand (Estimated Capital Cost—$0)*

From an equipment perspective, this is the same as Alternative 1. The costs of routine and major maintenance are included in the operating costs. The difference is in how the plant is operated. This type of operation is sometimes called "following the heat curve." It takes advantage of the electricity that is a "by-product" of using a steam turbine in place of a pressure reducing valve to go from the boiler pressure (nominally 400 psig) to the heating system distribution pressure (nominally 100 psig) in this case.

The use of condensing steam turbines results in the need to produce some steam flow and subsequent electrical generation beyond the "heat curve" (extraction) requirements because of cooling requirements for the lower pressure stages of the turbine downstream from extraction point to the condenser. This cooling flow produces additional power by going through all stages of the turbine to the condenser. The cooling steam flow is estimated to be 10 percent of the throttle flow to the turbine. The throttle flow at the peak heating demand is estimated to be 352,400 lb/hr, 317,200 lb/hr for heating demand and 35,200 lb/hr for turbine cooling. The additional flow for cooling generates an extra 2.9 MW at the estimated peak heating demand, about 2.5 MW net. Since the peak heating steam demand provides 8.0 MW (9.4 MW gross) and the additional cooling flow 2.5 MW, 10.5 MW is the maximum available power when following the heat curve.

At the end of the study period the interconnection with GVEA will need to be at least 24 MVA (19.2 MW at 80 percent pf) to cover the estimated peak. The n-1 turbine condition does not influence the interconnection size since the maximum generation can be provided in the n-1 condition. The maximum steam demand of 352,400 lb/hr is lower than the n-3 boiler capacity.

There are no permitting requirements for this alternative. Emission rates remain the same per ton of coal consumed.

Providing dual fuel capability would involve retrofitting fuel oil or natural gas burners to the boilers. The new burners would require new combustion controls and burner management systems. Fuel oil would also involve unloading, storage, and transfer systems. Natural gas, if pipeline gas became available, would involve piping the supply to the boilers. LNG would involve storage and vaporization facilities. A detailed analysis of the boi-

lers would be necessary to determine if firing fuel oil or natural gas would result in a derating of the boilers.

The key factors in evaluating this option are the same as the Alternative 1 with a larger amount of power being purchased from GVEA. It is necessary to account for the additional fuel associated with producing the condenser steam for turbine cooling, but this will be much lower than in Alternative 1.

Improved fuel efficiency will result with this Alternative.

This alternative has the following advantage(s):

- no capital investment
- continue under existing environmental permits
- reduced onsite coal use
- maximizes fuel efficiency
- minimizes coal consumption.

This alternative has the following disadvantage(s):

- continuing dependence on aging CHPP
- increased operations and maintenance requirements over time
- exposure to significant outages from equipment failure
- minimizes onsite electrical generation, purchase electricity in all years, increased costs from purchased power.

*Alternative 4: Upgrade with New CFBs and an Additional STG (Estimated Capital Cost—$104,895,000)*

This option is being considered in the current long range planning for the CHPP at Eielson. The plan being considered would add two new CFBs with the same steam conditions as the existing boilers and a new 20-MW steam turbine. Once the new CFBs are operating in a reliable manner, two of the existing boilers would be retired.

The new boilers and turbine would be added in an extension of the building at the Boiler 5 & 6, Turbine 5 end (north). Alternative 2 above indicates that the available steam with 720,000 lb/hr of installed boiler capacity supports 17.8 MW of added steam turbine capacity (42.8 MW gross less 25 MW installed), exceeding the estimated maximum demand. Meeting the estimated peak electrical demand requires an additional 10 MW of installed steam turbine capacity. Therefore, the planned addition of a

20 MW steam turbine allows the retirement of 10 MW of existing capacity. It is assumed that the two 2.5-MW units would be retired. The footprint for the new CFBs and a 20-MW steam turbine should work with an extension of the current building.

This alternative most likely can use offsets from retiring two boilers to avoid a PSD management/NAA permit. The ability to avoid PSD management/NAA permitting will depend on the quantity of past actual emissions from the boilers being retired and the control systems provided with the new boilers. Installation of SNCR on the new CFBs will result in a significant reduction in NOx emissions. The use of limestone for in-bed $SO_2$ reduction will also provide reduced emissions compared to the boilers being retired. Particulate removal would be done with a baghouse. It is expected that improved combustion efficiency will result in lower CO and VOC emissions. The emission of HAPs should also be lower than alternatives involving the existing facility. This alternative will result in slightly fewer total emissions. The CFBs will have lower emission rates, however, there will be an increase in the quantity of coal consumed. The offsets from retiring two boilers should allow relatively straightforward minor construction permitting with standard emission controls installed on the new CFBs. The remaining boilers would not be affected.

Dual fuel capability could be incorporated in the design of the new CFBs. Burners for fuel oil or natural gas and appropriate combustion controls and burner management systems would be required. An inert material such as sand would be required in the bed to allow the CFBs to maintain their heat transfer characteristics with either fuel oil or natural gas.

The general scope of this alternative includes the construction of an extension to the power plant building, installation of two new CFBs each with SNCR and baghouses for emission controls, installing a STG with associated mat foundation, air-cooled condenser, coal handling extension, limestone handling, ammonia storage and transfer, and associated balance of plant and electrical systems. This is viewed as a difficult retrofit with loss of labor productivity because of tight working areas within an operating plant, difficult positioning of construction equipment, and remote laydown area resulting in the double handling of materials.

The considerations in evaluating this option include the capital investment for the new equipment and building, operating and maintenance cost with a mix of new and old equipment, addition of limestone and ammonia as

reagents for emission controls, and an interconnection with GVEA of 25 MVA (20 MW at 80 percent pf) to cover the n-1 turbine condition. The CFBs also provide an opportunity to use lower quality coal that could result in a discount compared to the current coal price.

Significant operating efficiency improvements (labor, fuel, etc.) would not be anticipated.

This alternative has the following advantage(s):

- new boilers utilize cleaner technology, reduced emissions
- self-sufficiency for heat and electricity
- improved fuel efficiency
- improved operational efficiency
- uses a "secure" fuel
- allows abandonment of Boilers 5 and 6.

This alternative has the following disadvantage(s):

- capital investment required.

*Alternative 5: New Plant Using CFBs and STGs (Estimated Capital Cost—$107,510,000)*

A new plant can be designed with a more efficient steam cycle for the production of electricity. The current plant using 400 psig/650 °F steam has an ideal Rankine cycle efficiency of about 35 percent (typical actual efficiency would be up to about 25 percent). A plant using 850 psig/900 °F steam has an ideal Rankine cycle efficiency of about 40 percent, a five percentage point improvement.

The plant is sized to concurrently meet the projected peak heating demand (317,200 lb/hr) and generate the projected electrical peak demand (29.7 MW) using condensing STGs rated for 850 psig/900 °F steam at the throttle with a 100 psig extraction point to provide heating steam and allowing 12 percent of the gross generation for auxiliary power. The projected electrical peak of 29.7 MW requires generation of 33.8 MW with auxiliary power of 12 percent. Considering the peak heating steam demand and allowing for feedwater heating typical of a cycle using these steam conditions, the throttle flow to generate MW is approximately 620,000 lb/hr. Using four boilers requires a capacity of 155,000 lb/hr each. Three boilers could be provided and the peak heating steam plus part of the electrical demand can be satisfied in the n-1 boiler condition. However, the

current plant has significant redundancy for steam generation and four boilers for this option that would allow the estimated peak heating demand to be satisfied in the n-2 boiler condition would provide better reliability. Therefore, the use of four boilers with a slight increase in capacity to 160,000 lb/hr is the basis for this option. Steam turbines are generally more reliable than boilers and back-up or replacement power can be provided via other means (such as the GVEA interconnection and diesel generators). Providing the generating capacity in three STGs would require nominal ratings of 12 MW each and is considered the basis for this option.

Four boilers in the n-1 condition provide 480,000 lb/hr of steam. The estimated generation under this condition concurrent with the peak heating demand is 25.8 MW gross, 22.7 MW net. This is 7 MW short of the peak. The n-1 turbine condition is larger, about 12 MW short of the peak electrical demand, and should be satisfied by the GVEA interconnection. The GVEA interconnection needs to have a capacity of 15 MVA (12 MW at 80 percent pf) to cover the n-1 turbine condition.

The n-2 boiler condition provides the estimated peak heating steam, but since it requires essentially all of the available steam it has a significant impact on the power generation. The estimated generation is 9.7 MW gross (8.5 MW net). Therefore, meeting the peak electrical demand requires an additional 21.2 MW. The additional power can be provided by a combination of the GVEA interconnection and the back-up diesel generators. The GVEA interconnection should be at least 15 MVA to cover the n-1 turbine condition to minimize the use of diesels under normal maintenance conditions. Since 12/16/20 MVA is a standard transformer size for GVEA, a 20 MVA (16 MW) interconnection should be considered. The current diesel generators provide 6 MW in their n-1 condition. Therefore, the diesel generators plus a 20 MVA GVEA interconnection can provide the additional 21.2 MW to satisfy concurrent peak heating steam and electrical demands in the n-2 boiler condition. Therefore, the new plant will consist of four 160,000-lb/hr CFBs, three nominal 12-MW steam turbines, continued availability of the current diesel generators, and a 20-MVA GVEA interconnection.

Emission controls include selective non-catalytic reduction with ammonia as the reagent for NOx, use of limestone for in-bed $SO_2$ reduction, and a baghouse for PM removal. It is expected that improved combustion efficiency will result in lower CO and VOC emissions. The emission of HAPs should also be lower than alternatives involving the existing facility. The

shutting down of existing boilers provides an offset in emissions allowing a minor construction permit and standard emission controls on the new CFBs.

The generators for the steam turbines would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability could be incorporated in the design of the new boilers. Burners for fuel oil or natural gas and appropriate combustion controls and burner management systems would be required. An inert material such as sand would be required in the bed to allow the CFBs to maintain their heat transfer characteristics with either fuel oil or natural gas.

It is assumed that the area north of the current plant can be used for a new plant. The area would be close to the existing coal receiving, cooling pond, and switchyard. The use of this area would allow relatively easy interfacing with the utilidor system.

The general scope of this alternative includes a new standalone plant consisting of four CFBs each with SNCR and baghouses for emission controls, three STGs, air-cooled condensers, coal handling, limestone handling, ash handling, balance of plant systems, building, rail spur extension, and substation.

Evaluation of this option includes the significant capital investment associated with a new plant, reduced O&M compared to the existing plant, a more efficient cycle, and a similar number of operating personnel. The existing diesels will need to remain available for back-up service. There will be a need to purchase electricity from GVEA at times of high demand if equipment is out of service. The CFBs also provide an opportunity to use lower quality coal that could result in a discount compared to the current coal price.

This alternative has the following advantage(s):

- new cleaner technology, reduced emissions
- self-sufficiency for heat and electricity
- improved fuel efficiency
- improved operational efficiency

- allows abandonment (and demolition) of existing CHPP
- uses a "secure" fuel.

This alternative has the following disadvantage(s):

- capital investment required.

*Alternative 6: CT Cogeneration (HRSG for heat): Liquid Fuel (Estimated Capital Cost—$88,158,000)*

The projected 2028 peak electrical demand, 29.7 MW, can be satisfied by CTs. The CTs will provide exhaust heat that can be recovered to produce steam in an HRSG. This steam can be used to either generate additional electricity in a steam turbine (a combined cycle) or directly as heating steam (CT cogeneration). The relatively high ratio of peak heating demand to peak electricity demand favors using the HRSG steam directly, the CT cogeneration approach. Auxiliary power for this type of plant is conservatively estimated to be 5 percent of gross output, resulting in a need to generate a total of about 31.3 MW. The Solar Mars 100 has a nominal rating of 10 MW. The peak electrical demand can be satisfied by three Mars 100 CTs at ambient temperatures below about 50 °F. Full load output for industrial-type CTs, such as the Mars 100, varies significantly with ambient temperature. A Mars 100 full load output ranges from about 9 MW to about 16 MW over the ambient temperature range of +70 to –40 °F. Heat recovery steam generators (HRSGs) would be used to directly provide heating steam. Each HRSG would need to provide approximately 106,000 lb/hr to the heating system. The unfired condition would provide about 50,000 lb/hr. It is generally feasible to double the HRSG output by duct firing without substantial impact on the HRSG design. Therefore, this combination appears to be a good match for the peak demands. The installation of three CT/HRSGs units will be examined to address the n-1 conditions. While there are other potential gas turbines for the application, the Mars 100 has been used as a basis since it is representative and performance and cost information is readily available.

The CT n-1 condition impacts the ability to provide both heat and electricity at high demands. The loss of a CT essentially creates an n-1 condition for the HRSGs. The loss of another HRSG would create an n-2 HRSG condition even though only one HRSG had failed. It is possible to use additional fuel oil to replace the heat input from the CT exhaust with the addition of a fresh air fan to the HRSG, but complete isolation of the CT to allow maintenance while operating its associated HRSG is a potential op-

erational safety issue. Satisfying the peak heating steam demand in a single HRSGs is not feasible. The most practical solution appears to be the inclusion of an oil-fired 212,000 lb/hr package boiler to improve the reliability of providing back-up heating steam. Since the peak electrical demand is expected to occur during arctic winter conditions when CT output is higher, the CT n-1 condition will meet the peak electrical demand. The new plant basis is three Solar Mars 100 CTs, three single-pressure HRSGs with duct firing designed to provide 106,000 lb/hr each, and an oil-fired 212,000 lb/hr auxiliary boiler. The GVEA interconnection should be sized for 13 MVA (10.4 MW at 80 percent pf) to cover the loss of generation from a CT.

The net emissions from shutting down of the existing boilers allows the use of a minor construction permit. NOx emission controls consists of water or steam injection in conjunction with SCR. The $SO_2$ emissions will be a function of the sulfur level in the fuel oil. Ultra-low sulfur fuel oils are not readily available in the Fairbanks area, but the low sulfur fuels available result in lower $SO_2$ emissions than the current plant. CO and VOCs will be reduced via high combustion efficiency and oxidation catalyst. Formaldehyde is the primary concern for HAPs and could equal the total HAPs from the coal-fired alternatives. In summary, overall emissions should be as low as the best coal-fired alternative and probably better.

The generators for the CTs would have individual generator breakers and be connected at the generator voltage to a generator bus. The generator bus would feed the substation via two 100 percent capacity generator step-up transformers. The substation would use a ring bus configuration.

Dual fuel capability for the CTs and duct-firing of the HRSGs would require natural gas. Dual fuel capability with fuel oil and natural gas are relatively common for CTs and HRSGs and involve different combustors and burners respectively. Natural gas would result in lower emissions and reduced maintenance compared to fuel oil.

The area north of the current plant would be used for the CT cogeneration plant. Oil delivery, transfer, and storage facilities are included for the new plant. There could be operating conditions, such as peak heating steam demand with less than peak electrical demand, that result in excess generation to meet the heating demand. Provisions to provide electricity to GVEA would be beneficial and need to be considered.

The general scope of this alternative includes a new standalone plant consisting of three CTs, three single-pressure HRSGs with duct firing, SCRs, CO catalyst, oil receiving, storage, and transfer; balance of plant systems, package boiler, building, and substation.

The evaluation of this option includes the capital investment, consumption of liquid fuel, and O&M requirements. The firing of the HRSGs will provide some flexibility to meet heating loads independent of electrical demands. However, CT efficiency of operation at part loads is generally much lower than at full load. Also, it will be necessary to follow electrical demand unless GVEA is willing to purchase electricity at times.

This alternative has the following advantage(s):

- lower capital cost
- new clean technology, reduced emissions
- self-sufficiency for heat and electricity
- high fuel efficiency
- improved operational efficiency
- allows abandonment (and demolition) of existing CHPP
- conversion to natural gas, if available
- improved operational efficiency
- reduced emissions from improved emissions control.

This alternative has the following disadvantage(s):

- relatively expensive fuel, volatile prices
- less secure fuel
- shorter economic life.

## Estimated Pollutant Emissions

Emissions of NOx, CO, $SO_2$, PM, and VOCs were estimated for each combustion source for the alternatives. The air pollutant emission estimates were made using EPA's *Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources,* which contains emission factors for coal-fired boilers and CTs. The emission factors are expressed as mass of pollutant emissions per unit of fuel input. Table 38 lists the emission factors used in the emission estimation calculations.

Table 38. Air pollutant emission factors, compilation emission factors, AP-42, 5th ed., vol 1: "Stationary Point and Area Sources" (EPA).

| Pollutant | Spreader Stoker Sub-Bituminous Boilers (lb/ton) | Fluidized-Bed Combustion, Circulating Bed (lb/ton) | Distillate Oil-Fired Turbines | | Gas-Fired Turbines | |
|---|---|---|---|---|---|---|
| | | | Uncontrolled (lb/MMBtu) | Water-Steam Injection (lb/MMBtu) | Uncontrolled (lb/MMBtu) | Water-Steam Injection (lb/MMBtu) |
| NOx | 8.80 | 5.00 | 0.88 | 0.240 | 0.320 | 0.130 |
| CO | 5.00 | 18.00 | 0.0033 | 0.076 | 0.082 | 0.030 |
| $SO_2$ | 7.00 | 1.39 | 0.303 | | 0.470 | |
| PM | 66.00 | 12.00 | 0.00041 | | 0.0021 | |
| VOCs | 0.05 | 0.05 | 0.0120 | | 0.0066 | |

The emission factors for $SO_2$ were dependent on the fuel sulfur content. Assumed sulfur weight percentages were 0.2 for coal, 0.3 for fuel oil, and 0.5 for natural gas. The $SO_2$ emission factor for the CFB also depended on the calcium to sulfur ratio used in the boiler bed to reduce $SO_2$ emissions. This ratio was assumed to be 2.5. The heat content of fuel oil and coal also were required in some of the estimation calculations. The coal heat content was assumed to be 7,900 Btu/lb, and the fuel oil heat content 0.125328 MMBtu/gal.

All emission estimates were made based on fuel required to meet heating and electrical power demands in 2015. This year was selected because it would be the first year that all proposed heat and power generation alternatives would be fully deployed. Table 39 lists the fuel usage estimates for all of the installation-specific and regional alternatives.

Table 39. 2015 Fuel usage by alternative.

| Alternative | Coal/Fuel Oil (Tons/Gal) | | |
|---|---|---|---|
| | FWA | EAFB | Regional |
| *Regional Alternative* | | | |
| 1 | 192,600 | 134,000 | 345,300 |
| 2 | 192,600 | 134,000 | 11,431,000 |
| 3 | - | - | 515,200 |
| 4 | - | - | 41,941,000 |
| *Installation-Specific Alternative* | | | |
| 1 | 235,600 | 210,700 | - |
| 2 | 315,100 | 210,700 | - |
| 3 | 192,600 | 134,000 | - |
| 4 (stoker) | NA | 86,100 | - |
| 4 (CFB) | NA | 86,100 | - |
| 5 | 225,800 | 160,000 | - |
| 6 | 21,729,000 | 13,944,000 | - |

The emissions from combustion sources are sometimes reduced by applying control equipment to the flue gas stream. Chapter 13 describes some of the typical air pollution controls employed for combustion emissions. These control devices are most often employed on new sources of air pollution, but may also be required when an existing source goes through a major modification. The existing stoker boilers will all be retrofitted with baghouses soon. The stoker boilers also likely would be required to add air pollution control under Installation-Specific Alternative 2 because this would be considered a major modification to FWA's and EAFB's CHPPs. For Alternative 2, it is assumed that dry scrubbing would be required to control $SO_2$ and SCR to control NOx.

For new CTs, it is assumed that water injection and SCR would be required to control NOx and catalytic oxidation to control CO. For new CFBs, it is assumed that a baghouse would control PM, limestone placed in the bed of the CFB in conjunction with the baghouse would control $SO_2$, and selective non-catalytic reduction (SNCR) would control NOx. Table 40 lists these pollution control assumptions and the amount of pollution reduction expected for each control system. The pollution reduction percentages were taken from AP-42. The AP-42 emission factors used for CTs and CFBs already account for reduction of NOx by water injection and reduction of $SO_2$ by CFB bed limestone. Two PM emission reduction estimates are given for PM because the gas stream leaving the CFBs will contain a larger percentage of small-diameter particles, and baghouses are less efficient for these smaller particles.

The emission factor and fuel information shown in Tables 39 and 40 were used to estimate uncontrolled air pollutant emissions from the alternatives. Tables 41 and 42 show the uncontrolled pollutant emission estimates for regional and installation-specific alternatives, respectively. In the case of alternatives using CFBs, the control of $SO_2$ emissions from limestone in the bed is included in the emission estimates of Regional Alternatives 1 and 3 and Installation-Specific Alternatives 4 and 5. The control of NOx emissions from new combustion turbines through water injection is included in the emission estimates for Regional Alternatives 2 and 4 and Installation-Specific Alternative 6.

Table 40. Pollution control assumptions.

| Pollutant | Control | Reduction (%) | Used for |
|---|---|---|---|
| PM | Baghouse | 99.8 | Stoker boiler |
| PM | Baghouse | 99.5 | CFB |
| $SO_2$ | Dry scrubber | 80.0 | Stoker boiler |
| NOx | SCR | 80.0 | Stoker boiler and turbine |
| NOx | SNCR | 45.0 | CFB |
| CO | Catalytic oxidation | 92.0 | Turbine |

Table 41. Uncontrolled emission calculations for regional alternatives in 2015 (tpy).

| Alternative | Control | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|---|
| 1 (FWA) | | 847.4 | 674.1 | 481.5 | 6,355.8 | 4.8 |
| 1 (EAFB) | | 589.6 | 469.0 | 335.0 | 4,422.0 | 3.4 |
| 1 (CFB) | Limestone in bed | 863.3 | 239.8 | 3,107.7 | 2,071.8 | 8.6 |
| 2 (FWA) | | 847.4 | 674.1 | 481.5 | 6,355.8 | 4.8 |
| 2 (EAFB) | | 589.6 | 469.0 | 335.0 | 4,422.0 | 3.4 |
| 2 (turbine) | Water inject | 171.9 | 217.0 | 54.4 | 8.6 | 0.3 |
| 3 (CFB) | Limestone in bed | 1,288.0 | 357.8 | 4,636.8 | 3,091.2 | 12.9 |
| 4 (turbine) | Water inject | 630.8 | 796.3 | 199.7 | 31.5 | 1.1 |

Table 42. Uncontrolled emission calculations for installation-specific alternatives in 2015 (tpy).

| Alternative | Control | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|---|
| 1 (FWA) | | 1,036.6 | 824.6 | 589.0 | 7,774.8 | 5.9 |
| 1 (EAFB) | | 927.1 | 737.5 | 526.8 | 6,953.1 | 5.3 |
| 2 (FWA) | | 1,386.4 | 1,102.9 | 787.8 | 10,398.3 | 7.9 |
| 2 (EAFB) | | 927.1 | 737.5 | 526.8 | 6,953.1 | 5.3 |
| 3 (FWA) | | 847.4 | 674.1 | 481.5 | 6,355.8 | 4.8 |
| 3 (EAFB) | | 589.6 | 469.0 | 335.0 | 4,422.0 | 3.4 |
| 4 (EAFB – stoker) | | 378.8 | 301.4 | 215.3 | 2,841.5 | 2.2 |
| 4 (EAFB – CFB) | Limestone in bed | 215.3 | 59.8 | 774.9 | 516.6 | 2.2 |
| 5 (FWA) | Limestone in bed | 564.5 | 156.8 | 2,032.2 | 1,354.8 | 5.6 |
| 5 (EAFB) | Limestone in bed | 400.0 | 111.1 | 1,440.0 | 960.0 | 4.0 |
| 6 (FWA) | Water inject | 326.8 | 412.6 | 103.5 | 16.3 | 0.6 |
| 6 (EAFB) | Water inject | 209.7 | 264.8 | 66.4 | 10.5 | 0.4 |

Tables 43 and 44 show the results of applying the emission control assumptions displayed in Table 40. Table 45 lists combined emissions from FWA and EAFB for the installation-specific alternatives. Because Installation-Specific Alternative 4 was not applicable to FWA, FWA's Alternative 5 emissions were added to EAFB's Alternative 4 emissions.

Table 43. Controlled emission calculations for regional alternatives in 2015 (tpy).

| Alternative | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|
| 1 (FWA) | 847.4 | 674.1 | 481.5 | 12.7 | 4.8 |
| 1 (EAFB) | 589.6 | 469.0 | 335.0 | 8.8 | 3.4 |
| 1 (CFB) | 474.8 | 239.8 | 3,107.7 | 10.4 | 8.6 |
| 2 (FWA) | 847.4 | 674.1 | 481.5 | 12.7 | 4.8 |
| 2 (EAFB) | 589.6 | 469.0 | 335.0 | 8.8 | 3.4 |
| 2 (turbine) | 34.4 | 217.0 | 4.4 | 8.6 | 0.3 |
| 3 (CFB) | 708.4 | 357.8 | 4,636.8 | 15.5 | 12.9 |
| 4 (turbine) | 126.2 | 796.3 | 16.0 | 31.5 | 1.1 |

Table 44. Controlled emission calculations for installation-specific alternatives in 2015 (tpy).

| Alternative | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|
| 1 (FWA) | 1,036.6 | 824.6 | 589.0 | 15.5 | 5.9 |
| 1 (EAFB) | 927.1 | 737.5 | 526.8 | 13.9 | 5.3 |
| 2 (FWA) | 277.3 | 220.6 | 787.8 | 20.8 | 7.9 |
| 2 (EAFB) | 185.4 | 147.5 | 526.8 | 13.9 | 5.3 |
| 3 (FWA) | 847.4 | 674.1 | 481.5 | 12.7 | 4.8 |
| 3 (EAFB) | 589.6 | 469.0 | 335.0 | 8.8 | 3.4 |
| 4 (EAFB – stoker) | 378.8 | 301.4 | 215.3 | 5.7 | 2.2 |
| 4 (EAFB – CFB) | 118.4 | 59.8 | 774.9 | 2.6 | 2.2 |
| 5 (FWA) | 310.5 | 156.8 | 2,032.2 | 6.8 | 5.6 |
| 5 (EAFB) | 220.0 | 111.1 | 1,440.0 | 4.8 | 4.0 |
| 6 (FWA) | 65.4 | 412.6 | 8.3 | 16.3 | 0.6 |
| 6 (EAFB) | 41.9 | 264.8 | 5.3 | 10.5 | 0.4 |

The emission estimates listed in Table 45 do not account for emissions generated from the production of electricity imported by FWA and EAFB. To account for those, emissions assumptions had to be made about new sources of electricity that will be available to GVEA in 2015, the distribution among all sources of electricity available to GVEA, the probable use of these electrical energy assets, and the air pollution control applied to combustion sources generating electricity for GVEA. The first assumption is that 54 MW of power will become available from a coal-fired plant at Healy. This plant is assumed to have emission controls and reductions that are the same as for the CFB, as discussed above.

Table 45. Controlled emission summations for all alternatives in 2015 (tpy).

| Alternative | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|
| Regional 1 | 1,911.8 | 1,382.9 | 3,924.2 | 31.9 | 16.8 |
| Regional 2 | 1,471.4 | 1,360.1 | 820.9 | 30.2 | 8.5 |
| Regional 3 | 708.4 | 357.8 | 4,636.8 | 15.5 | 12.9 |
| Regional 4 | 126.2 | 796.3 | 16.0 | 31.5 | 1.1 |
| Installation-Specific 1 | 1,963.7 | 1,562.1 | 1,115.8 | 29.5 | 11.2 |
| Installation-Specific 2 | 462.7 | 368.1 | 1,314.5 | 34.7 | 13.1 |
| Installation-Specific 3 | 1,437.0 | 1,143.1 | 816.5 | 21.6 | 8.2 |
| Installation-Specific 4 | 807.7 | 517.9 | 3,022.4 | 15.0 | 10.0 |
| Installation-Specific 5 | 530.5 | 267.9 | 3,472.2 | 11.6 | 9.6 |
| Installation-Specific 6 | 107.3 | 677.3 | 13.6 | 26.8 | 0.9 |

The distribution among available electrical power assets was based on a likely allocation of GVEA resources during a peak demand day in 2015. The peak demand for 2015 was projected to be 206 MW by using the peak demand of 179 MW reported in GVEA's 2002 annual report with a 1.1 percent annual growth rate. The 1.1 percent growth rate is the "middle" population growth rate forecast for the Fairbanks North Star Borough by the state demographer.* The peak demand was used because it is under peak demand conditions that FWA and EAFB are most likely to import electricity from GVEA.

Table 46 lists electrical energy sources available to GVEA and their capacity. Table 46 does not include power that GVEA imports from the Anchorage area that is generated almost exclusively from gas-fired CTs. Chapter 7 states that even with anticipated improvement of the Intertie, imported energy will be limited to 55 MW. This assumes that a new coal-fired boiler at Healy comes online. Chapter 7 also discusses the economic attractiveness of electrical energy resources. Because of high fuel oil prices, imported energy from the Intertie and Aurora Energy and energy generated from Healy's coal-fired plants are more economical sources than electrical energy produced by GVEA's oil-fired turbines. Table 46 lists data showing how GVEA might distribute a demand of 206 MW if it uses its cheapest sources of electricity first. Table 47 lists distribution by type of generation under this scenario; existing coal-fired boilers fall into the old category and the new Healy coal-fired plant falls into the new category.

* State of Alaska, Department of Labor, Research & Analysis, *Alaska Economic TREND* (State Census & Geographic Information Network Department, 2001), accessed May 2001 through URL: www.state.ak.us

Table 46. GVEA electrical generation for peak demand in 2015.

| Source | Capacity (MW) | Type | Running Total for Peak Demand (MW) |
|---|---|---|---|
| Bradley Lake | 20 | Hydro | 206 |
| Anchorage | 55 | Gas | 186 |
| Existing Healy | 25 | Coal-fired (old) | 131 |
| New Healy | 54 | Coal-fired (new) | 106 |
| Aurora | 20 | Coal-fired (old) | 52 |
| Rest (oil CT) | | Oil (CT) | 32 |

Table 47. Distributions among GVEA sources of electricity.

| Type of Generation | % Total |
|---|---|
| Hydro | 9.7 |
| Gas turbine | 26.6 |
| Coal-fired (old) | 21.8 |
| Coal-fired (new) | 26.2 |
| Oil (CT) | 15.7 |

FWA and EAFB import electricity from GVEA only under Installation-Specific Alternatives 1 and 3. In 2015, it is anticipated that FWA will require 55,716 MWh and 87,370 MWh of imported electricity under Alternatives 1 and 3, respectively. At EAFB, the imported electricity requirements will be 7,740 MWh and 67,657 MWh for Alternatives 1 and 3, respectively. Heating values for CTs (10,000 Btu/kWh) and coal-fired boilers (14,000 Btu/kWh) were obtained from the data listed in Table 7. The heating values were used to convert electrical energy requirements to fuel requirements.

The same emission estimation methods that were used to calculate emissions from installation-specific and regional alternatives were also used to estimate emissions from the types of sources listed in Table 47. The electricity generated by the Bradley Lake hydroelectric power facility obviously does not produce any air pollutant emissions. It was assumed that all gas-fired CTs used water injection to control NOx, all coal-fired boilers used baghouses to control PM, that the new coal-fired boilers at Healy achieved the same emission reductions for $SO_2$ and NOx that the CFB could achieve, and that oil-fired CTs did not use water injection to control NOx. Tables 48 and 49 show emission estimates based on these assumptions about the distribution of electrical energy sources and air pollution control. Table 50 lists all energy and power alternatives when the emissions from GVEA are included for Installation-Specific Alternatives 1 and 3.

Table 48. Controlled GVEA emission estimations for FWA installation-specific alternatives 1 and 3 in 2015 (tpy).

| Alternative | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|
| *FWA 1* | | | | | |
| Coal-fired (old) | 47.37 | 37.68 | 26.91 | 0.71 | 0.27 |
| Coal-fired (new) | 17.76 | 8.97 | 116.27 | 0.39 | 0.32 |
| Oil CT | 38.44 | 13.24 | 0.14 | 0.52 | 0.02 |
| Gas CT | 9.65 | 34.90 | 2.23 | 0.49 | 0.16 |
| *Total* | *113.23* | *94.78* | *145.56* | *2.11* | *0.77* |
| *FWA 3* | | | | | |
| Coal-fired (old) | 74.28 | 59.09 | 42.21 | 1.11 | 0.42 |
| Coal-fired (new) | 27.86 | 14.07 | 182.33 | 0.61 | 0.51 |
| Oil CT | 60.28 | 20.75 | 0.23 | 0.82 | 0.03 |
| Gas CT | 15.14 | 54.72 | 3.49 | 0.77 | 0.24 |
| *Total* | *177.55* | *148.63* | *228.25* | *3.31* | *1.20* |

Table 49. Controlled GVEA Emission Estimations for EAFB Installation-Specific Alternatives 1 and 3 in 2015 (tpy).

| Alternative | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|
| *EAFB 1* | | | | | |
| Coal-fired (old) | 6.58 | 5.23 | 3.74 | 0.10 | 0.04 |
| Coal-fired (new) | 2.47 | 1.25 | 16.15 | 0.05 | 0.04 |
| Oil CT | 5.34 | 1.84 | 0.02 | 0.07 | 0.00 |
| Gas CT | 1.34 | 4.85 | 0.31 | 0.07 | 0.02 |
| *Total* | *15.73* | *13.17* | *20.22* | *0.29* | *0.11* |
| *EAFB 3* | | | | | |
| Coal-fired (old) | 57.52 | 45.76 | 32.68 | 0.86 | 0.33 |
| Coal-fired (new) | 21.57 | 10.89 | 141.19 | 0.47 | 0.39 |
| Oil CT | 46.68 | 16.07 | 0.18 | 0.64 | 0.02 |
| Gas CT | 11.72 | 42.38 | 2.70 | 0.60 | 0.19 |
| *Total* | *137.49* | *115.10* | *176.75* | *2.57* | *0.93* |

Table 50. Controlled Emission Summations for All Alternatives, including GVEA Contribution in 2015 (tpy).

| Alternative | NOx | SOx | CO | PM | VOCs |
|---|---|---|---|---|---|
| Regional 1 | 1,911.8 | 1,382.9 | 3,924.2 | 31.9 | 16.8 |
| Regional 2 | 1,471.4 | 1,360.1 | 820.9 | 30.2 | 8.5 |
| Regional 3 | 708.4 | 357.8 | 4,636.8 | 6.2 | 12.9 |
| Regional 4 | 126.2 | 796.3 | 16.0 | 31.5 | 1.1 |
| Installation-Specific 1 | 2,092.7 | 1,670.0 | 1,281.5 | 31.9 | 12.0 |
| Installation-Specific 2 | 462.7 | 368.1 | 1,314.5 | 34.7 | 13.1 |
| Installation-Specific 3 | 1,752.1 | 1,406.8 | 1,221.5 | 27.4 | 10.3 |
| Installation-Specific 4 | 807.7 | 517.9 | 3,022.4 | 15.0 | 10.0 |
| Installation-Specific 5 | 530.5 | 267.9 | 3,472.2 | 11.6 | 9.6 |
| Installation-Specific 6 | 107.3 | 677.3 | 13.6 | 26.8 | 0.9 |

# 16 Life-Cycle Cost Analysis

This Chapter discusses the key assumptions used in the life-cycle cost analysis, including:

- projected fuel prices
- planned near-term investments
- timing of alternatives
- assumptions used in the economic analysis
- life-cycle cost results.

## Projected Fuel Prices

Concurrent with this study, the Railbelt Utilities conducted a study of the generation needs for the Railbelt area. This group shared the fuel price projections it used in its analysis. These prices (Table 51) are used for this study's projection of annual operating costs for the various alternatives evaluated. Note that the prices (dollars per MMBtu) are in real dollars (no general inflation). Figure 25 shows a graph of the projected prices.

The price projections include mine-mouth coal for GVEA, heavy atmospheric gas oil (HAGO or fuel oil No. 4) used by GVEA for its CTs, naphtha (the proposed fuel for GVEA's NPE, diesel fuel (fuel oil No. 2) and Cook Inlet natural gas. Because of an anticipated tightening of Cook Inlet area gas supply, the price of natural gas is projected to double by about 2014 and then remains relatively constant.

The cost of delivered coal to FWA and EAFB is based on the current UCM coal contract through 2007. Beyond 2007, the prices were projected using the same year-to-year change as projected for GVEA mine mouth coal. This implicitly assumes that there is no real change in the cost of transportation from the mine to the installations. Note that the cost of coal is projected to decrease slightly in real terms. This is consistent with the vast reserves of consistent-quality sub-bituminous coal and the limited markets for this coal.

Table 51. Projected fuel prices for economic analysis (real dollars per MMBtu).

| Year | Coal | | | Cook Inlet Natural Gas | North Pole Naphtha | Diesel | North Pole HAGO |
|---|---|---|---|---|---|---|---|
| | Mine Mouth to GVEA (Healy Coal) | FWA Delivered | EAFB Delivered | | | | |
| 2004 | $1.1431 | $3.1800 | $3.2300 | $2.3610 | $5.2789 | $7.3283 | $5.9995 |
| 2005 | $1.1362 | $3.1800 | $3.2300 | $2.1204 | $5.1165 | $7.2676 | $4.9755 |
| 2006 | $1.1294 | $3.1800 | $3.2300 | $1.9885 | $5.1498 | $7.2912 | $4.2774 |
| 2007 | $1.1226 | $3.1800 | $3.2300 | $2.0159 | $5.1790 | $7.3119 | $4.3424 |
| 2008 | $1.1159 | $3.1610 | $3.2107 | $2.0379 | $5.2080 | $7.3325 | $4.3828 |
| 2009 | $1.1092 | $3.1421 | $3.1915 | $2.2432 | $5.2373 | $7.3532 | $3.9456 |
| 2010 | $1.1026 | $3.1232 | $3.1723 | $2.6287 | $5.2664 | $7.3738 | $4.1576 |
| 2011 | $1.0959 | $3.1045 | $3.1533 | $3.0098 | $5.2977 | $7.3959 | $4.2808 |
| 2012 | $1.0894 | $3.0859 | $3.1344 | $3.3814 | $5.3268 | $7.4166 | $4.3540 |
| 2013 | $1.0828 | $3.0673 | $3.1156 | $4.0996 | $5.3560 | $7.4372 | $4.3991 |
| 2014 | $1.0763 | $3.0490 | $3.0969 | $4.4491 | $5.3872 | $7.4593 | $4.4285 |
| 2015 | $1.0699 | $3.0307 | $3.0783 | $4.3594 | $5.4184 | $7.4814 | $4.4491 |
| 2016 | $1.0635 | $3.0125 | $3.0598 | $4.3098 | $5.4497 | $7.5036 | $4.3594 |
| 2017 | $1.0571 | $2.9944 | $3.0415 | $4.2831 | $5.4809 | $7.5257 | $4.3099 |
| 2018 | $1.0507 | $2.9764 | $3.0232 | $4.2691 | $5.5142 | $7.5493 | $4.2831 |
| 2019 | $1.0444 | $2.9585 | $3.0050 | $4.2622 | $5.5454 | $7.5714 | $4.2691 |
| 2020 | $1.0382 | $2.9408 | $2.9870 | $4.2595 | $5.5767 | $7.5935 | $4.2622 |
| 2021 | $1.0319 | $2.9232 | $2.9691 | $4.2591 | $5.6225 | $7.6259 | $4.2595 |
| 2022 | $1.0257 | $2.9056 | $2.9513 | $4.2591 | $5.6683 | $7.6584 | $4.2591 |
| 2023 | $1.0196 | $2.8882 | $2.9336 | $4.2591 | $5.7141 | $7.6908 | $4.2591 |
| 2024 | $1.0134 | $2.8708 | $2.9159 | $4.2591 | $5.7578 | $7.7218 | $4.2591 |
| 2025 | $1.0074 | $2.8537 | $2.8985 | $4.2591 | $5.8036 | $7.7542 | $4.2591 |
| 2026 | $1.0013 | $2.8365 | $2.8811 | $4.2591 | $5.8479 | $7.7856 | $4.2591 |
| 2027 | $0.9953 | $2.8195 | $2.8638 | $4.2591 | $5.8925 | $7.8172 | $4.2591 |
| 2028 | $0.9894 | $2.8026 | $2.8467 | $4.2591 | $5.9374 | $7.8490 | $4.2591 |
| Coal prices per DESC contract. Fixed through 2007. | | | | | | | |

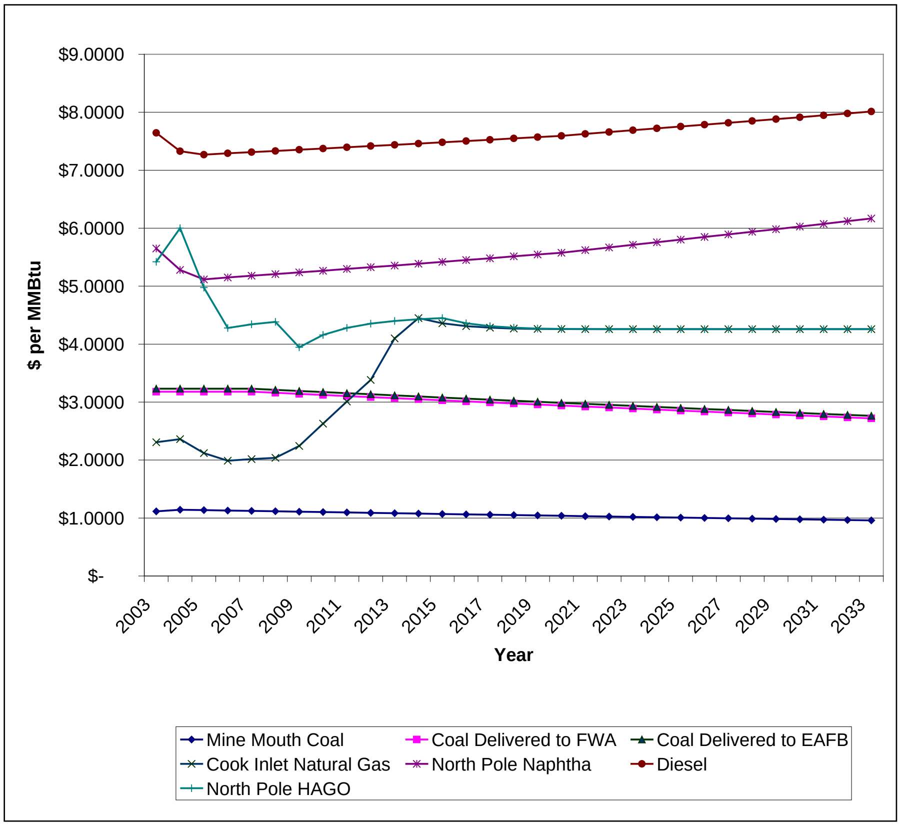



Figure 25. Projected prices.

From the graph, it can be seen that diesel fuel is projected to be the most expensive fuel and naphtha is also projected to be a relatively expensive fuel. The projection for HAGO is for new supply contracts and suggests that HAGO and natural gas will compete for use in CTs if and when natural gas becomes available in the Fairbanks area.

## Planned Near-Term Investments

A number of central heat and power related projects (planned near-term investments) have been identified at both FWA and EAFB. These projects address known deficiencies. The FWA projects were identified in the study entitled Conversion of CHPP to Heating Only and Provide Backup Electrical Generators, Fort Wainwright, March 2003. The EAFB projects were identified in the study entitled Environmental & Engineering Options Study, Central Heat and Power Plant, Eielson AFB, AK, September 2001. Our review found that the projects should occur in several of the alternatives identified for each installation. For those alternatives where continued operation of the existing CHPPs is assumed to occur, the investments are assumed to be made (FWA-1, 2, 3; EAFB 1, 2, 3, 4; Regional 1 and 2). For those alternatives where the project would be inappropriate if a timely

decision is made to pursue that alternative, the project is assumed not to occur.

Table 52 lists these projects at FWA and EAFB that are assumed to take place in the period 2004 to 2012 if the plants are expected to continue to operate.

### FWA

At FWA, there are two significant projects in the near term that are expected to receive authorization this year:

1. *Air-Cooled Condenser Project*. This project will install an air-cooled condenser at the CHPP to greatly reduce the need to use the cooling pond. A primary benefit is the elimination of ice fog from the cooling pond along the Richardson Highway in winter. We assume that this is a $29.3 million dollar project with construction expected in 2006 for Alternatives 1, 2, and 3 and Regional Alternatives 1 and 2.
2. *Phase 2, Boiler Repair*. This project will repair additional CHPP boiler and piping systems with the intent that at the completion of the work, the CHPP will have no known major deficiencies and will comply with the applicable codes. We have assumed that this $17.8 million project will be accomplished in 2005 for Alternatives 1, 2, and 3 and Regional Alternatives 1 and 2.

Several other smaller projects were also identified and are listed in Table 52. They include upgrade of the electric system switchgear, expansion of the FWA substation interconnection to GVEA, upgrade of the plant control system, and governor upgrades. These are assumed to occur for Alternatives 1, 2, and 3. For Alternatives 5 and 6 and Regional Alternatives 3 and 4, only the electric switchgear and substation are assumed to occur.

The March 2003 CHPP to Heating Only Study identified the need to install backup generation onsite at FWA to provide the capability to serve base loads without reliance on GVEA. This is a capability that does not now exist. For this comparative analysis, we have assumed that 32.5 MW of backup generation, at a cost of $35 million, will be installed in 2007 for all of the alternatives evaluated. This project does not have any formal status, and no efforts have been made to seek either authorization or funding. Because the investment is assumed for all of the FWA and Regional alternatives, it does not affect the comparative analysis. It does however add to

the net present value (NPV) of all of the alternatives. If backup generation is not added, this capital cost would not be incurred.

Table 52. Planned investments in CHPP-related plant, Fort Wainwright, and Eielson Air Force Base.

| Item | Investment ($ millions) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
| FWA | | | | | | | | |
| Air-cooled Condenser Upgrade | | | $29.30 | | | | | |
| Phase 2 CHPP Repair | | $17.80 | | | | | | |
| Electric System Switchgear | | $2.00 | | | | | | |
| 138/12.47, 12/16/20 MVA Substation | | $4.32 | | | | | | |
| Upgrade to Ovation Control System | | | $3.85 | | | | | |
| Governor Upgrade | | | $1.50 | | | | | |
| Backup Generation | | | | $35.00 | | | | |
| Total | $0 | $24.12 | $34.65 | $35.00 | $0 | $0 | $0 | $0 |
| EAFB | | | | | | | | |
| Rebuild boiler 5 | | $3.60 | | | | | | |
| Rebuild boiler 6 | | | $2.00 | | | | | |
| New Control System | | | | | | | | $10.00 |
| Expand/improve makeup air system in powerhouse | | | | $1.39 | | | | |
| Add rail spur for outdoor coal unloading | | | | | $0.41 | | | |
| New coal handling facility separate from CHPP | | | | | $7.99 | | | |
| Add redundant coal handling w/reserve bunker | | | | | $6.70 | | | |
| Rebuild pump house and intake structure at cooling pond | | | | | | $0.56 | | |
| Install new full-stream condensate polishing system | | | | | | $0.48 | | |
| Install additional well for summer plant cooling | | | | | | $0.60 | | |
| Total | $0 | $3.60 | $2.00 | $1.39 | $15.10 | $1.64 | $0 | $10.00 |

### EAFB

As discussed above, the EAFB planned projects were identified in a September 2001 study. The major projects include rebuilding Boilers 5 and 6 to return the two boilers to their rated capacity and to perform needed maintenance. We have assumed that this work will be done in 2004 ($3.6 million) and 2005 ($2.0 million) for those alternatives that keep the CHPP in operation (Alternatives 1 through 4 and Regional Alternatives 1 and 2). EAFB has indicated that Boilers 5 and 6 eventually may be replaced.

The report also recommended:

- Replacing the control system in 2011
- Improving the makeup air system
- Adding a new rail spur for outdoor coal unloading
- Building a new coal unloading facility
- Adding redundant coal handling
- Improvements to the cooling water supply system
- Installation of a new condensate polishing system

For Alternatives 1 through 4 and Regional Alternatives 1 and 2, which keep the CHPP in service, these projects are included. For Alternatives 5 and 6 and Regional Alternatives 3 and 4, which replace the existing CHPP, only the cooling water projects were included.

The investments described above are projects that each installation plans to make or should make during this period. There are other heat and power related projects (utilidor upgrades, backup heat plants, etc.) that have not been included because they are outside the scope of this analysis. To the extent they are common to an installation's alternatives, they would not affect the comparative results.

A decision to not include the projects listed in Table 52 would affect the comparative analysis to the extent that a project should be done under one alternative(s), but not under others.

## Timing of Alternatives

For this analysis, it has been assumed that a significant new project (new boilers, new STGs, new power plant, new heat and power plant) would have an eight-year lead time to complete the planning, budgeting, engineering and permitting, construction, and commissioning process. That is,

none of the alternatives would come online until 2012, which was selected because it provides about 2 years to make a decision on which alternative to pursue and a 7-year lead time for project development (engineering, permitting, construction, and startup). Seven years is appropriate for a new coal-fired plant. Using the same lead-time for all alternatives places them on the same footing for comparison purposes. If an alternative can be brought online in a shorter period of time, it would have a relatively higher NPV for the capital investment and annual operating costs. Assuming the same year for all alternatives makes the comparative cost analysis easier to interpret. If appropriate or necessary, the actual schedule could be extended.

Because of this assumption, the costs to continue to operate the existing CHPPs are included in all of the alternatives for 2004 through 2011. The mode of existing CHPP operation is somewhat different in Alternatives 1, 2, and 3. For Alternatives 4, 5, and 6, it is assumed that the CHPPs will be operated so that each installation is as self-sufficient as possible. This choice was made because each installation can generate an incremental kWh of electricity less expensively than it can purchase one.

## Economic Analysis

The following elements were involved in preparing the economic analysis:

- Develop projections of heating and electrical needs (discussed previously).
- Define Alternatives based on technologies and installation loads (discussed previously).
- Develop capital cost estimates for each Alternative. (The scope for each estimate is discussed under the definition of each alternative.)
- Develop a 25-year operational model (2004 through 2028) for each alternative to determine fuel use and costs, labor costs, and routine and major maintenance costs.
- Compute the NPV for the 25 years of operation.
- Compute the NPV of the capital costs for the Planned Investments and for each Alternative.
- Add the NPV of the operational costs and capital costs to establish the life-cycle costs for each Alternative.

### Assumptions Used

This analysis compares the life-cycle costs of the alternatives. To the extent a given assumption is reflected in all of the alternatives, a change in the

assumption will be reflected in all alternatives. Only to the extent a change in an assumption affects the alternatives differently will the comparison of the alternatives change. For example, changing the discount rate will alter the NPV values, but will not change the relative NPVs of the alternatives. Changing the cost of coal, but not changing the cost of fuel oil will change the NPVs of coal-based alternatives versus those of oil-based alternatives.

In conducting the analysis, the following assumptions were used:

- Use of constant (real) dollars (2004 $), as compared to nominal dollars. That is, the price of a good or service is not affected by the rate of general inflation.
- Fuel prices as discussed in the section “Projected Fuel Prices.”
- A coal heat content of 7,800 Btu/lb.
- A boiler efficiency of 78 percent for the existing boilers. For new CFBs, an efficiency of 82 percent was used.
- For CT alternatives, fuel consumptions were determined for average conditions in 2012 and 2028. Values for intermediate years were based on linear interpolation.
- Real price increases by GVEA of 5 percent every 5 years. It is assumed that GS-2 rate structure remains the same for the study period for each installation.
- GVEA electricity purchases at the same load factor as the Installation’s overall electricity usage load factor. To the extent an installation does not have sufficient capacity to meet its own loads, this has the effect of placing load growth on GVEA.
- CHPP staffing as shown in the Figure 26. From 2004 through 2011, the staffing levels are the same as now for both FWA (56) and EAFB (60). Starting 2012, the staffing levels were adjusted to reflect either the increased maintenance requirements for continuing to operate the CHPPs or to reflect new plant with improved controls and reduced maintenance requirements.

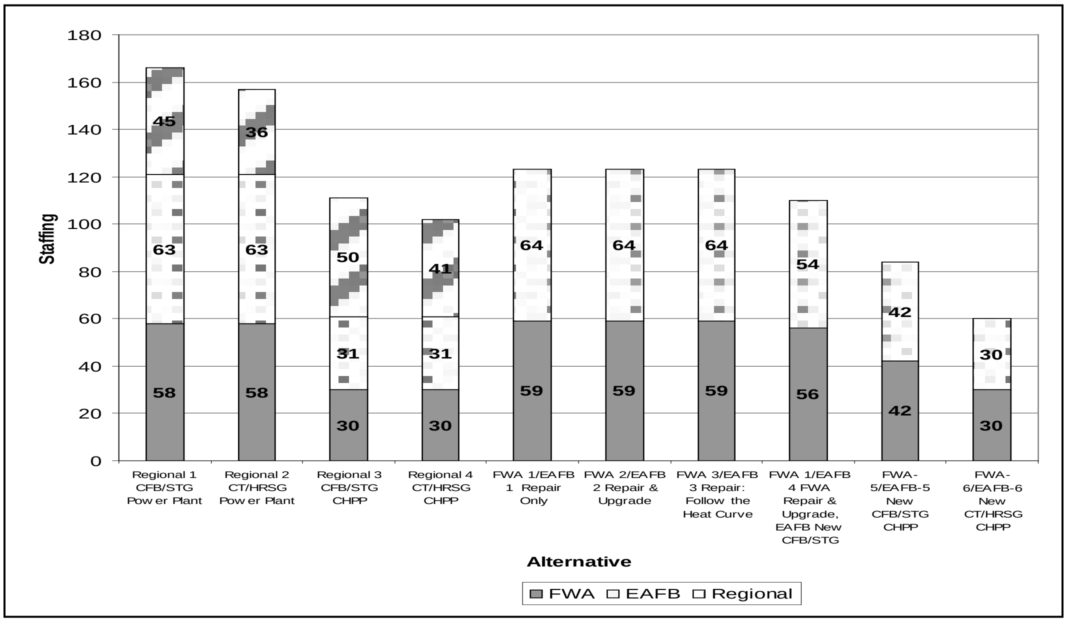



Figure 26. Average CHPP staffing levels over study period.

- An average 2004 labor cost of $81,000 per full time equivalent (FTE) in 2004 and real labor cost increases of 1 percent per year. This is consistent with costs used in prior studies.
- Real materials cost increases of 1 percent per year.
- The same Routine and Major Maintenance costs for each alternative that continues the operation of the existing CHPPs, whether at FWA or EAFB.
- Reduced Routine and Major Maintenance costs for each alternative that replaces the existing CHPPs with new plants (FWA and EAFB Alternatives 5 and 6, and Regional Alternatives 3 and 4).
- An annual CT/HRSG maintenance cost, including both Routine and Major Maintenance, of $24 per MWh for installation-specific alternatives and $20 per MWh for a regional plant. This is consistent with the costs used by the Railbelt Utilities in its analysis.
- Capital costs in the year in which a project is commissioned.
- The capital investments as discussed in "Planned Near-term Investments" (p 241).

The capital investment for each Alternative assume:

- Additional substation capacity for the GVEA interconnections as needed to allow the import of electricity as needed for a given alternative. Note that no GVEA costs for transmission system improvements were included.

- New coal-fired alternatives were assumed to have an economic life of 50 years. CT alternatives were assumed to have an economic life of 30 years.
- For those projects with an expected economic life of less than 25 years, a second same-dollar-amount investment in the year after the end of the expected economic life.
- Demolition of the existing CHPPs in 2015 for FWA Alternatives 5 and 6, EAFB Alternatives 5 and 6, and for Regional Alternatives 3 and 4 (new regional CHPP). For all other alternatives, no CHPP demolition costs were included.
- A 2028 capital cost, residual value credit that reflects a straight-line computation based on remaining life of the asset. For example, a 50-year project installed in 2012 has a residual value in 2028 equal to 68 percent of its initial cost, and this value is credited in 2028 against the capital cost of the project.
- Real discount rate of 3.2 percent
- End-of-year prices and discount factors
- The base date is considered to be the beginning of the first year of the study period, 2004.

No distinction was made between ownership and financing approaches for a particular project or alternative.

The analysis for each Alternative provides the following information, both by year and NPV:

- Coal consumption and cost
- Lime use and cost
- Limestone use and cost
- Fuel oil consumption and cost
- Purchased electricity and cost
- Labor cost (including an allocation to heat and electricity)
- Routine and Major Maintenance costs (including an allocation to heat and electricity)
- Total Operating Costs (including an allocation to heat and electricity)
- Annual assumed staff and 25-year average staff

## Results of Analysis

### *General Observations*

The first two Regional Alternatives provide for regional power supply only; installation heat requirements are met by continued operation of the exist-

ing CHPPs. Once the regional power plants are on-line, the existing CHPPs would operate in a “follow the heat curve” mode to maximize fuel efficiency at the installation. This results in electricity generation onsite. These alternatives are at a relative disadvantage because of the continued operation of the two existing CHPPs plus the new regional power plant.

The third and fourth Regional Alternatives assume that a regional CHPP is constructed to provide heat and electricity to both installations. These alternatives have relatively high capital costs because of the need to construct a heat transmission system from the new CHPP to each installation.

For both FWA and EAFB, Alternatives 1 (Repair Only), Alternatives 2 (Repair and Upgrade with Increased STG Capacity), and Alternatives 3 (Repair and Follow the Heat Curve) yield essentially the same life-cycle costs. All involve the continued use of the existing CHPPs.

Alternative 1 most closely resembles current operations. For FWA this involves purchasing its electrical load growth from GVEA; it is able to meet its heat loads from the existing boilers. EAFB purchases power from GVEA beginning 2012 and meets its electrical load growth thereafter with GVEA purchases.

Alternative 2 evaluates the addition of more STG capacity at each installation. This is important for FWA because it is at the point where the existing onsite generation capacity is very close to the projected peak under –60 °F conditions. Any shortfall must be purchased from GVEA. EAFB has adequate capacity to meet its loads without GVEA purchases until 2012. Under this alternative, FWA purchases its electrical load growth from GVEA until 2012, at which point, the additional STG capacity allows it to meet its own loads. This is the only alternative not involving a new facility that requires the addition of emission controls.

Alternative 3 is very similar to Alternative 1, except the CHPPs are operated to follow the heat curve. The operational mode reduces the amount of onsite generation to maximize fuel efficiency; as a result, it also maximizes the purchases from GVEA. The cost of producing an incremental kWh onsite (fuel cost only) is less expensive than purchasing an incremental kWh from GVEA for both installations.

Alternative 4 for EAFB is the recommended course of action from the 2001 Environmental & Engineering Options Study and is somewhat similar to

Alternative 2, except that new CFBs are installed, Boilers 5 and 6 are abandoned, and a new STG is added. (There is no Alternative 4 for FWA.)

Alternative 5 is to replace the existing CHPPs in 2012 with new coal-fired CFB CHPPs and demolish the old ones 3 years later. This alternative provides updated coal burning technology, emissions controls, improved boiler efficiency, updated coal handling, modern controls, and reduced O&M costs.

Alternative 6 replaces the existing CHPPs with new oil-fired CTs and HRSGs and demolition of the existing CHPPs in 2015. This alternative provides reduced capital costs, reduced operation and maintenance costs, and reduced costs for emissions controls.

*Regional Alternatives*

The data in Table 53 and Figure 27 show the results of the Regional Alternative life-cycle cost analysis. The life-cycle costs are within 20 percent or less of the lowest cost alternative, a new regional coal-fired CHPP. A longer evaluation period would favor this alternative because of lower fuel costs.

Table 53. NPV of life-cycle costs for regional alternatives.

| Description | | Electricity Only | | Heat and Electricity | |
|---|---|---|---|---|---|
| | | Regional 1 CFB/STG | Regional 2 CT/HRSG | Regional 3 CFB/STG CHPP | Regional 4 CT/HRSG CHPP |
| NPV of Annual Operating Costs ($1,000)[1] | | | | | |
| Existing CHPPs | | | | | |
| FWA | | Repair, Follow Heat Curve 2012 | | Through 2015 | |
| Heat | | $229,256 | $229,256 | $86,971 | $86,971 |
| Electricity | | $159,690 | $159,690 | $83,132 | $83,132 |
| Purchased Power | | $79,179 | $79,179 | $18,627 | $18,627 |
| Subtotal | | $468,125 | $468,125 | $188,730 | $188,730 |
| EAFB | | Repair, Follow Heat Curve 2012 | | Through 2015 | |
| Heat | | $181,069 | $181,069 | $62,906 | $62,906 |
| Electricity | | $179,226 | $179,226 | $99,851 | $99,851 |
| Purchased Power | | $71,931 | $71,931 | $4 | $4 |
| Subtotal | | $432,226 | $432,226 | $162,761 | $162,761 |
| FGA and GMD Purchased Power | | $34,184 | $34,184 | $34,184 | $34,184 |
| Regional Plant Only | | | | | |
| Heat | | $- | $- | $255,773 | $363,193 |
| Electricity | | $273,712 | $244,966 | $244,996 | $357,821 |
| GVEA Wheeling Charges | | $50,470 | $50,470 | $50,470 | $50,470 |
| Subtotal | | $324,182 | $295,435 | $551,239 | $771,483 |
| Operating Cost NPV | | $1,258,717 | $1,229,970 | $936,914 | $1,157,159 |

| | | | | | |
|---|---|---|---|---|---|
| NPV of Capital Investments ($1,000) | | | | | |
| Planned Improvement Work | | $96,873 | $96,873 | $40,345 | $40,345 |
| Capital Cost of Alternative (incl. demo as approp.) | | $137,037 | $89,360 | $284,397 | $186,007 |
| Capital Cost NPV | | $233,909 | $186,233 | $324,742 | $226,352 |
| NPV OF ALTERNATIVE ($1,000) | | $1,492,626 | $1,416,203 | $1,261,657 | $1,383,511 |
| Tons of Coal Consumed (25 Years) | Tons x 1,000 | 15,535 | 9,113 | 12,869 | 3,485 |
| Fuel Oil Consumed | Gallons x 1000 | - | 230,519 | - | 749,352 |
| Average No. of Employees (over 25 yrs) | | 56 | 45 | 50 | 46 |
| 1 Does not include Capital Costs. | | | | | |

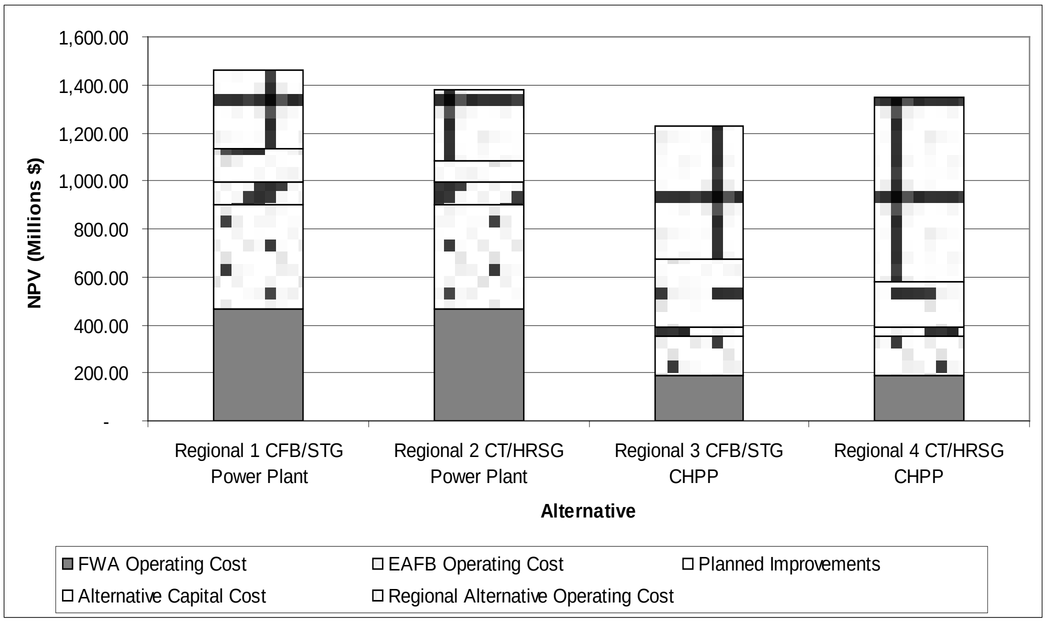



Figure 27. Regional alternatives.

The two regional electricity alternatives, Regional 1: Coal-fired CFBs/STGs and Regional 2: Oil-fired CTs/HRSGs have life-cycle costs that are within 6 percent of each other. The continued operation of the FWA and EAFB CHPPs is common to both alternatives. Even though the capital cost of the CT/HRSG approach is considerably less than the CFB/ STG, the increased fuel costs from using fuel oil offset much of the capital cost savings.

The two regional CHPP alternatives, Regional 3, Coal-Fired CFBs/STGs, and Regional 4, CTs/HRSGs, include higher capital costs for the heat transmission system. The existing CHPPs are assumed to cease operation when the new regional CHPP comes online, providing significant savings in labor and maintenance. The coal-fired alternative has the lowest life-cycle cost of the regional alternatives at $1,262 million. This is about 10 percent less than the life-cycle cost of the oil-fired regional CHPP.

*FWA*

Table 54 lists the life-cycle cost analysis for FWA. Figure 28 shows the components of the life-cycle costs graphically.

Table 54. NPV of Life-Cycle Costs for installation-specific alternatives—Fort Wainwright.

| Description | | FWA-1 Repair Only | FWA-2 Repair & Upgrade | FWA-3 Repair: Follow the Heat Curve | FWA-5 New CFB/ STG CHPP | FWA-6 New CT/ HRSG CHPP |
|---|---|---|---|---|---|---|
| NPV of Annual Operating Costs ($1,000)[1] | | | | | | |
| On-Base Heat and Electricity[2] | | | | | | |
| Heat Cost | | $214,399 | $195,156 | $239,880 | $185,140 | $285,452 |
| Electricity | | $194,008 | $263,155 | $132,329 | $200,232 | $167,376 |
| Subtotal | | $408,406 | $458,311 | $372,208 | $385,372 | $452,828 |
| Purchased Power | | $79,179 | $18,641 | $124,345 | $18,641 | $18,641 |
| Total Annual Operating Cost | | $487,585 | $476,952 | $496,553 | $404,013 | $471,469 |
| NPV of Capital Investments ($1,000) | | | | | | |
| Planned Improvement Work | | $78,707 | $78,707 | $78,707 | $72,972 | $72,972 |
| Capital Cost of Alternative (incl. Demo as approp.) | | $- | $49,019 | $1,376 | $98,823 | $63,597 |
| Total Capital Cost NPV | | $78,707 | $127,726 | $80,082 | $171,795 | $136,568 |
| **TOTAL NPV OF ALTERNATIVE ($1,000)** | | **$566,292** | **$604,679** | **$576,636** | **$575,808** | **$608,037** |
| Tons of Coal Consumed (25 Years) | Tonsx1,000 | 5,884 | 7,612 | 4,805 | 6,360 | 1,830 |
| Fuel Oil Consumed (gallons) | Gallonsx1,000 | - | - | - | - | 387,914 |
| Average No. of Employees (over 25 yrs) | | 58 | 58 | 58 | 46 | 38 |

[1] Does not incl. Capital Costs.
[2] Excluding purchased electricity.

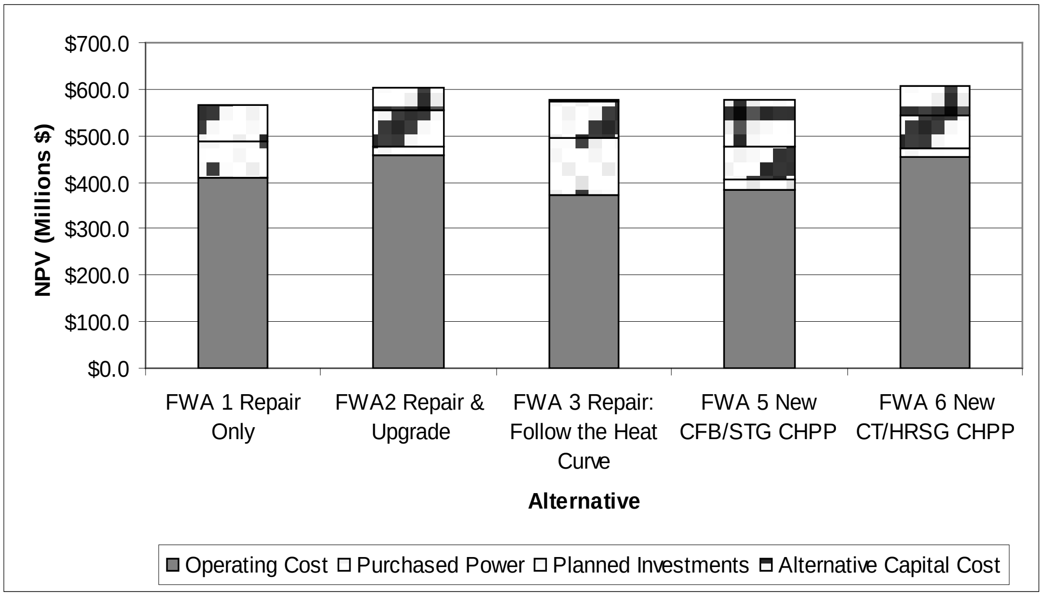



Figure 28. Fort Wainwright—summary of life-cycle costs.

The life-cycle costs of the five alternatives are within 7 percent or less of the lowest alternative. The costs for three of the alternatives, Alternatives 1, 3, and 5, are within 2 percent of one another despite significant differences in the alternatives. This result is well within the cumulative uncertainty of the numerous assumptions made to accomplish the analysis.

The closeness of the results reflects that "new" alternatives do not come online until 2012. Reduced staffing levels, lower operation and maintenance costs, and improved fuel efficiency for 17 years just offset the capital costs for a new plant in the period evaluated. A longer evaluation period would favor the new coal-fired CHPP alternative because of reduced labor, operation and maintenance, and fuel costs.

With that in mind, it can be seen that Alternative 1, Repair, has the lowest life-cycle cost. Alternative 5, New CFB and STG CHPP, and Alternative 3, Repair and Follow the Heat Curve, have essentially the same life-cycle cost.

Alternative 1 has the second highest life-cycle operating costs.

Alternative 2, Repair and Upgrade, has relatively high capital costs to retrofit additional emission controls. This results in it having relatively high life-cycle capital costs.

Alternative 3 has the highest life-cycle operating cost.

Alternative 5 has the lowest life-cycle operating cost. As a result, if a longer evaluation period were used, Alternative 5 would have comparably lower life-cycle costs.

Alternative 6, New CT and HRSG CHPP, has a life-cycle cost that is about 6 percent higher than Alternative 5, primarily because of higher fuel costs.

*Sensitivity of FWA Results*

These results were tested for sensitivity to load growth and to determine how much the capital costs for Alternative 5 would have to change to result in the same life-cycle cost as for each of the other alternatives without any changes to the other alternatives' capital costs.

If 0 percent load growth is assumed at FWA after demolition of the New Bassett Hospital in 2009, the capacity needed in 2028 is reduced from 36.3 MW to 24.4 MW, a 33 percent reduction. If the capital costs for the alternatives are unchanged, the existing CHPP Alternatives 1 and 3 have the lowest life-cycle costs. For Alternative 5 to have the lowest life-cycle cost under a no-load growth scenario, its capital costs would need to decrease by 25 percent. (If it is known that lower load growth is expected, the capital costs for Alternatives 5 and 6 would be less because less capacity would need to be installed.)

If Alternative 1 incurred additional life-cycle capital costs of $12.6 million or more over the 25-year period, its life-cycle costs would be the same as or greater than for Alternative 5.

If the capital costs for Alternative 5 were to decrease 10.7 percent with no change in the capital costs for Alternative 1, the life-cycle costs for these two alternatives would be the same. For Alternatives 2, 3, and 6, the Alternative 5 capital cost increases would need to be 32.4 percent, 0.9 percent, and 36.2 percent, respectively, for the life-cycle costs to be the same.

*EAFB*

Table 56 lists the life-cycle costs analysis for EAFB. Figure 29 shows the information graphically.

Table 55. NPV of life-cycle costs for installation-specific alternatives—Eielson Air Force Base.

| Description | | EAFB-1 | EAFB-2 | EAFB-3 | EAFB-4 | EAFB-5 | EAFB-6 |
|---|---|---|---|---|---|---|---|
| | | Repair Only | Repair & Upgrade | Repair: Follow the Heat Curve | New CFB/ STG | New CFB/ STG CHPP | New CT/ HRSG CHPP |
| NPV of Annual Operating Costs ($1,000)[1] | | | | | | | |
| On-Base Heat and Electricity[2] | | | | | | | |
| Heat Cost | | $152,158 | $153,053 | $197,569 | $161,314 | $143,433 | $199,938 |
| Electricity | | $244,153 | $245,833 | $138,331 | $205,090 | $181,340 | $157,374 |
| Subtotal | | $396,312 | $398,885 | $335,900 | $366,403 | $324,773 | $357,311 |
| Purchased Power | | $16,798 | $16,682 | $103,185 | $2,776 | $11 | $11 |
| Total Annual Operating Cost | | $413,110 | $415,567 | $439,085 | $369,180 | $324,784 | $357,323 |
| **NPV of Capital Investments ($1,000)** | | | | | | | |
| Planned Improvement Work | | $24,186 | $24,186 | $24,186 | $24,186 | $2,037 | $1,784 |
| Capital Cost of Alternative (incl. Demo as approp.) | | $- | $38,163 | $1,778 | $46,548 | $92,683 | $57,152 |
| Total Capital Cost NPV | | $24,186 | $62,349 | $25,964 | $70,734 | $94,719 | $58,936 |
| **TOTAL NPV OF ALTERNATIVE ($1,000)** | | **$437,296** | **$477,916** | **$465,049** | **$439,914** | **$419,504** | **$416,259** |
| Tons of Coal Consumed (25 Years) | Tonsx1,000 | 5,202 | 5,205 | 3,369 | 4,479 | 4,458 | 1,589 |
| Fuel Oil Consumed (gallons) | Gallonsx1,000 | - | - | - | - | - | 251,344 |
| Average No. of Employees (over 25 yrs) | | 63 | 63 | 63 | 56 | 48 | 40 |

[1] Does not incl. Capital Costs.
[2] Excluding purchased electricity.

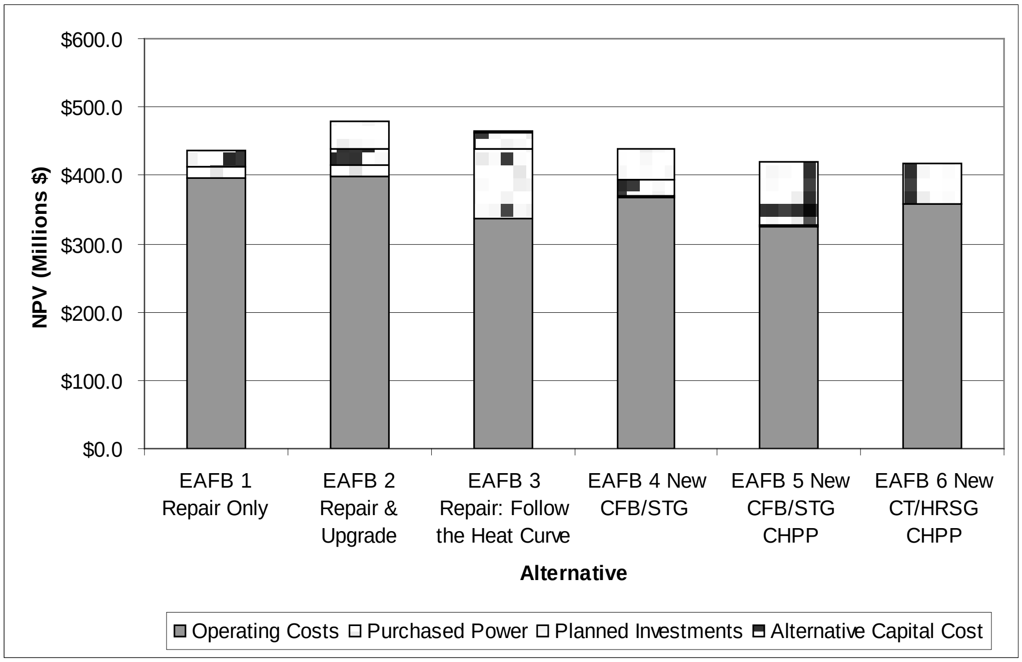



Figure 29. Eielson Air Force Base—summary of life-cycle costs.

The life-cycle costs of the six alternatives are within 14 percent or less of the lowest alternative. The costs for four of the alternatives, Alternatives 1, 4, 5, and 6, are within 5 percent of one another despite significant differences in the alternatives. This result is well within the cumulative uncertainty of the numerous assumptions made to accomplish the analysis.

The closeness of the results reflects that "new" alternatives do not come online until 2012. Reduced staffing levels, lower operation and maintenance costs, and improved fuel efficiency for 17 years just offset the capital costs for new plant in the period evaluated.

Alternative 6, New CT and HRSG CHPP, has the lowest life-cycle cost, followed closely by Alternative 5, New CFB and STG CHPP. Alternative 5 has the highest capital costs. A longer evaluation period would favor Alternative 5, New CFB/STG CHPP, because of lower fuel costs. A longer evaluation period would work against Alternative 6 because of the high cost of oil or natural gas.

Of the four alternatives involving continued operation of the existing CHPP, Alternative 1, Repair Only, has the lowest life-cycle cost. Alternative 3, Follow the Heat Curve, results in purchased power costs that are greater than the fuel savings. Alternative 2, Repair and Upgrade, has a significant capital cost to retrofit the required emissions controls. Alternative 4, In-

stall New CFBs, has a life-cycle cost that is within 0.6 percent of Alternative 1.

On a life-cycle cost basis, the new CHPP alternatives are the most cost-effective.

*Sensitivity of EAFP Results*

These results were tested for sensitivity to load growth and to determine how much the capital costs for Alternative 5 would have to increase to result in the same life-cycle cost as for each of the other alternatives without any changes to the other alternatives' capital costs.

Alternative 6 was found to have the lowest life-cycle costs, with electrical load growth at 0 percent beginning in 2004, assuming the capital costs for the alternatives are unchanged. Alternative 5 would have the second lowest life-cycle cost and then Alternative 1. The life-cycle costs for the three alternatives would be within 4 percent of one another.

If the capital costs for Alternative 5 were to decrease 3.9 percent with no change in the capital costs for Alternative 6, the life-cycle costs for these two alternatives would be the same. For Alternatives 1, 2, 3, and 4, the Alternative 5 capital cost increases would need to increase by 21.4 percent, 70.2 percent, 54.9 percent, and 24.5 percent, respectively.

*Comparison of Alternatives*

A meaningful comparison of the regional alternatives with installation-specific alternatives requires that the alternatives for FWA and EAFB be combined and compared against the regional alternatives.

The installation-specific combinations used are:

- FWA-1 and EAFB-1: Repair Only
- FWA-2 and EAFB-2: Upgrade with New STGs
- FWA-3 and EAFB-3: Repair Only, Follow the Heat Curve
- FWA-5: New CFB/STG CHPP and EAFB-4: New CFBs (2)
- FWA-5 and EAFB-5: New CFB/STG CHPP
- FWA-6 and EAFB-6: New CT/HRSG CHPP

The data listed in Table 56 and Figure 30 show the life-cycle costs for these combinations.

*Sensitivity of the Combined Analysis Results*

These results were tested for sensitivity to load growth and to determine how much the capital costs for Regional Alternative 3 would have to change to result in the same life-cycle cost as for the combined Installation-Specific Alternatives 5 without any changes to the other alternatives' capital costs.

At 0 percent electrical load growth for FWA and EAFB, the capital costs for Regional Alternative 3 would have to decrease by 48 percent for it to have the same life-cycle costs as the Installation-Specific Alternatives 5, assuming the capital costs for Alternatives 5 remain unchanged. This indicates that the advantages of the installation-specific solutions are not sensitive to load growth.

The capital costs for Regional Alternative 3 would need to decrease by 55 percent with no change in the capital costs for Installation-Specific Alternatives 5 for the life-cycle costs for the two alternatives to be the same. The life-cycle cost advantages of the installation-specific alternatives are sufficiently large as to make a regional alternative unattractive.

New coal-fired CHPPs at each installation have the lowest life-cycle costs. The coal-fired CHPPs' 25-year life-cycle costs are about 3 percent lower than for the oil-fired alternatives.

The new regional CHPP alternatives have life-cycle costs that are considerably higher (13 percent or more) than for the installation-specific new coal-fired CHPPs.

On the basis of life-cycle costs, construction of a new coal-fired CHPP at both FWA and EAFB provides the lowest life-cycle cost solution. On a 25-year basis, the coal-fired alternatives (FWA-5 and EAFB-5) have the lowest life-cycle costs. Because of fuel cost differences, the advantage of coal over oil would increase if a longer period was used.

Table 56. NPV life-cycle costs for regional alternatives and combined installation-specific alternatives.

| Description | Regional Alternatives | | | | Installation-Specific Alternatives | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Electricity Only | | Heat and Electricity | | | | | | | |
| | Reg. 1 CFB/STG Power Plant | Reg. 2 CT/HRSG Power Plant | Reg. 3 CFB/STG CHPP | Reg. 4 CT/HRSG CHPP | FWA 1/ EAFB 1 Repair Only | FWA 2/ EAFB 2 Repair and Upgrade | FWA 3/ EAFB 3 Repair: Follow the Heat Curve | FWA 5/EAFB 4 New CFB/STG CHPP (FWA) New CFB/STG (EAFB) | FWA 5/ EAFB 5 New CFB/STG CHPP | FWA 6/ EAFB 6 New CT/ HRSG CHPP |
| **NPV of Annual Operating Costs ($ millions; does not include capital costs)** | | | | | | | | | | |
| **Existing CHPPs** | | | | | | | | | | |
| FWA | Repair, follow heat curve 2012 | | Through 2015 | | | | | | | |
| Heat | $229.3 | $229.3 | $87.0 | $87.0 | $214.4 | $195.2 | $239.9 | $185.1 | $185.1 | $285.5 |
| Electricity | $159.7 | $159.7 | $83.1 | $83.1 | $194.0 | $263.2 | $132.3 | $200.2 | $200.2 | $167.4 |
| Purchased power | $79.2 | $79.2 | $18.6 | $18.6 | $79.2 | $18.6 | $124.3 | $18.6 | $18.6 | $18.6 |
| Subtotal | $468.1 | $468.1 | $188.7 | $188.7 | $487.6 | $477.0 | $496.6 | $404.0 | $404.0 | $471.5 |
| EAFB | Repair, follow heat curve 2012 | | Through 2015 | | | | | | | |
| Heat | $181.1 | $181.1 | $62.9 | $62.9 | $152.2 | $153.1 | $197.6 | $161.3 | $143.4 | $199.9 |
| Electricity | $179.2 | $179.2 | $99.9 | $99.9 | $244.2 | $245.8 | $138.3 | $205.1 | $181.3 | $157.4 |
| Purchased power | $71.9 | $71.9 | $0.0 | $0.0 | $16.8 | $16.7 | $103.2 | $2.8 | $0.0 | $0.0 |
| Subtotal | $432.2 | $432.2 | $162.8 | $162.8 | $413.1 | $415.6 | $439.1 | $369.2 | $324.8 | $357.3 |
| **FGA and GMD Purchased Power Cost** | $34.2 | $34.2 | $34.2 | $34.2 | $122.0 | $122.0 | $122.0 | $122.0 | $122.0 | $122.0 |
| **Regional Plant Only** | | | | | | | | | | |
| Heat | $- | $- | $255.8 | $363.2 | | | | | | |
| Electricity | $273.7 | $245.0 | $245.0 | $357.8 | | | | | | |
| GVEA wheeling charges | $50.5 | $50.5 | $50.5 | $50.5 | | | | | | |
| Subtotal | $324.2 | $295.4 | $551.2 | $771.5 | | | | | | |
| Operating Cost NPV | $1,258.7 | $1,230.0 | $936.9 | $1,157.2 | $1,022.6 | $1,014.5 | $1,057.6 | $895.1 | $850.8 | $950.7 |
| **NPV of Capital Investments ($ millions)** | | | | | | | | | | |
| Planned improvement work | $96.9 | $96.9 | $40.3 | $40.3 | $102.9 | $102.9 | $102.9 | $97.2 | $75.0 | $74.8 |
| Capital cost of alternative (incl. demo as appropriate) | $137.0 | $89.4 | $284.4 | $186.0 | $0 | $87.2 | $3.2 | $145.4 | $191.5 | $120.7 |
| Capital Cost NPV | $233.9 | $186.2 | $324.7 | $226.4 | $102.9 | $190.1 | $106.0 | $242.5 | $266.5 | $195.5 |
| **NPV of Alternative** | **$1,492.6** | **$1,416.2** | **$1,261.7** | **$1,383.5** | **$1,125.5** | **$1,204.5** | **$1,163.6** | **$1,137.7** | **$1,117.3** | **$1,146.2** |
| 1,000 Tons of Coal Consumed (25 yr) | 15,535 | 9,113 | 12,869 | 3,485 | 11,087 | 12,817 | 8,174 | 10.839 | 10,818 | 3,419 |
| Fuel Oil Consumed (1,000 gallons) | — | 230,519 | — | 749,352 | — | — | — | — | — | 639,258 |
| Average No. of Employees | 56 | 45 | 50 | 46 | 121 | 121 | 121 | 102 | 94 | 78 |

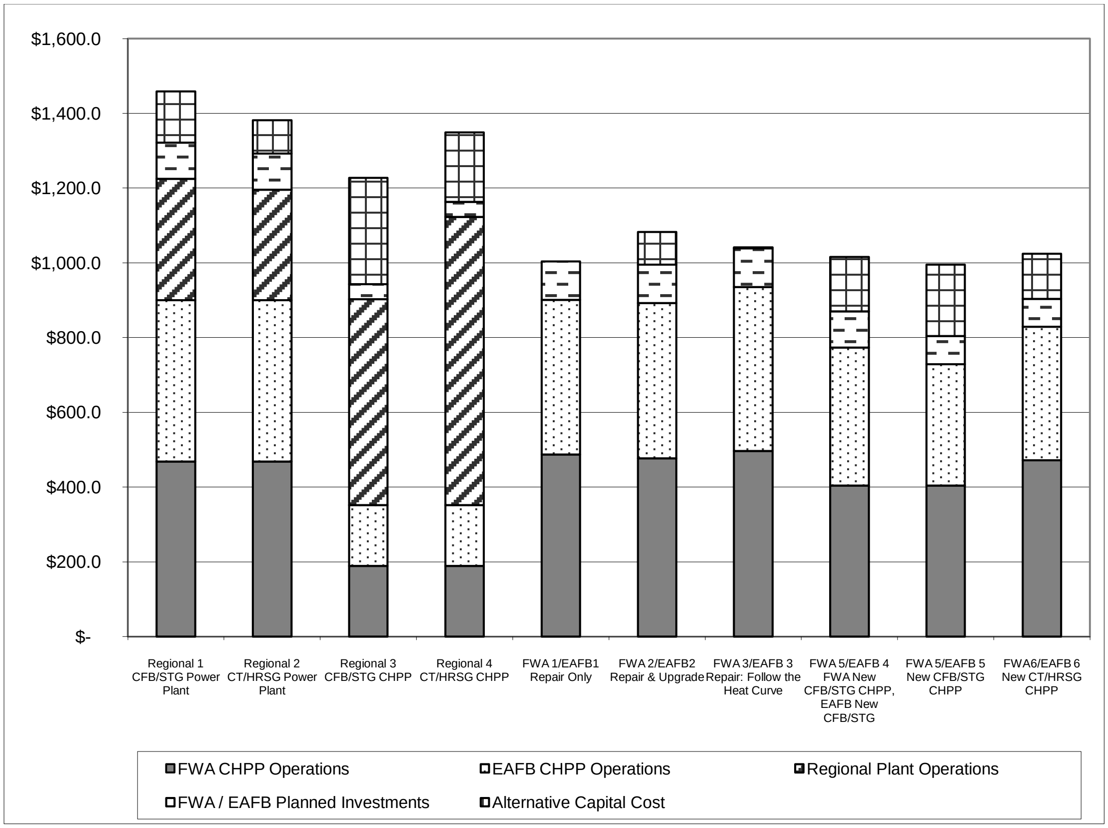



Figure 30. Summary of life-cycle cost analysis ($ millions).

# 17 Evaluation of Alternatives

## Criteria

As discussed in chapter 11, “Evaluation Criteria” (p 145), each alternative is evaluated against the following criteria with the indicated weighting:

- security—40 percent
- life-cycle costs—30 percent
- capital cost—7 percent
- air and water quality—5 percent
- cost stability—5 percent
- impact on Alaska infrastructure—5 percent
- water and solid waste reduction—5 percent
- operating cost—3 percent.

The life-cycle costs, capital cost, and operating costs were all developed in the life-cycle cost analysis and are quantitative rankings, each normalized to one. That is, the alternative with the lowest costs is ranked 10 and each alternative with higher costs is ranked less than 10 based on its relationship to the lowest cost alternative.

Security, cost stability, and impact on Alaska infrastructure are subjective measures based on a given alternative’s location, exposure to cost changes, and comparative use of Alaskan infrastructure.

Air and water quality, and water and solid waste reduction have quantifiable aspects and subjective aspects. Any alternative has to meet the applicable regulations and permitting requirements. The cost to meet these regulations is reflected in the life-cycle costs (including the capital cost and the operating cost). To be permitted, an alternative must have emissions that are not greater than permitted amounts. Assuming that is the case, meaningful differences among alternatives become difficult at this level of analysis. For this reason, the scoring for these criteria has been done on a relative basis and not on a quantitative basis.

As previously discussed, fuels were evaluated separately from the alternatives (cf. Table 30). Once the alternative is evaluated, that score, weighted at 70 percent is combined with the fuels score, weighted at 30 percent, to obtain the overall score for the alternative.

The following discussion is for the evaluation of the alternatives, the tables and figures include the scoring for the alternative and the fuel score for that alternative, with the resulting overall score indicated.

Sensitivity of the results to changes in weighting and scoring are then discussed.

As discussed in chapter 11 "Evaluation Criteria," Energy Surety has four components: Reliability, Security, Safety and Sustainability. Table 57 lists the scoring for each alternative for these four criteria. At this level of definition and design development, reliability differences among the alternatives were found to be impossible to quantify and, therefore, are not included in Table 57.

This information will be used to update the evaluation described below.

Table 57. Evaluation of energy surety.

| Alternative | | Fuel | Security | Safety | Sustainability |
|---|---|---|---|---|---|
| Regional Power Plant | | | | | |
| Regional 1 | CFB/STG Power Plant | Coal | 0.60 | 0.90 | 0.98 |
| Regional 2 | CT/HRSG Power Plant | Oil | 0.60 | 0.95 | 0.76 |
| Regional CHPP | | | | | |
| Regional 3 | CFB/STG CHPP | Coal | 0.20 | 0.90 | 0.98 |
| Regional 4 | CT/HRSG CHPP | Oil | 0.20 | 0.85 | 0.76 |
| Installation-Specific | | | | | |
| FWA 1/EAFB 1 | Repair Only | Coal | 1.00 | 0.65 | 0.98 |
| FWA 2/EAFB 2 | Repair and Upgrade | Coal | 1.00 | 0.80 | 0.98 |
| FWA 3/EAFB 3 | Repair: Follow the Heat Curve | Coal | 1.00 | 0.65 | 0.98 |
| FWA 2/EAFB 4 | FWA Repair and Upgrade, EAFB CFB/STG | Coal | 1.00 | 0.65 | 0.98 |
| FWA 5/EAFB 5 | New CFB CHPP | Coal | 1.00 | 0.75 | 0.98 |
| FWA 6/EAFB 6 | New CT/HRSG CHPP | Oil | 1.00 | 0.70 | 0.76 |

## Evaluation of Regional Alternatives

The same approach was used to score the regional alternatives, as discussed below (Table 58 and Figure 31).

### Security

Because the regional alternatives require that either electricity or heat or both be imported to one of the installations, the security from a "behind

the fence" perspective is diminished. For the power only alternatives, the security scores are the same as for the installation alternatives because the existing CHPPs continue to operate.

For FWA this results in reliance on the GVEA transmission system and the regional plant to meet its electrical load and its heat load if the regional plant is a CHPP. If the plant is "behind the fence" at EAFB and depending on the specific location, the GVEA transmission system may not be needed to deliver the power to EAFB. If the plant is "outside the fence" of both installations, then both would rely on the GVEA transmission system to deliver the electricity and on a heat transmission line to deliver the heat.

Table 58. Alternatives evaluation matrix—regional alternatives only, CHPP near EAFB.

| | | Electricity Only | | All Heat and Power | |
|---|---|---|---|---|---|
| | | Regional 1 CFB/STG Power Plant | Regional 2 CT/HRSG Power Plant | Regional 3 CFB/STG CHPP | Regional 4 CT/HRSG CHPP |
| Criteria | Weighting | Coal | Oil | Coal | Oil |
| Life-Cycle Cost | 30% | 8.50 | 8.90 | 10.00 | 9.10 |
| Security | 40% | 7.00 | 7.00 | 3.00 | 3.00 |
| Capital Cost | 7% | 8.00 | 10.00 | 5.70 | 8.20 |
| Air and Water Quality | 5% | 3.00 | 10.00 | 5.00 | 10.00 |
| Cost Stability | 5% | 10.00 | 5.00 | 10.00 | 5.00 |
| Impact on Alaska Infrastructure | 5% | 8.00 | 6.00 | 8.00 | 6.00 |
| Water and Solid Waste Reduction | 5% | 4.00 | 10.00 | 4.00 | 10.00 |
| Operating Cost | 3% | 7.40 | 7.60 | 10.00 | 8.10 |
| Total | 100% | | | | |
| Weighted ALTERNATIVE Score | | 7.38 | 7.95 | 6.25 | 6.30 |
| Index to Highest Score | | 0.93 | 1.00 | 0.79 | 0.79 |
| ALTERNATIVE Weighting | 70% | 0.65 | 0.70 | 0.55 | 0.55 |
| Indexed FUEL Score | | 0.98 | 0.76 | 0.98 | 0.76 |
| FUELS Weighting | 30% | 0.29 | 0.23 | 0.29 | 0.23 |
| OVERALL Ranking | | 0.94 | 0.93 | 0.84 | 0.78 |
| All criteria are evaluated qualitatively, except Life-Cycle Cost, Capital Cost, and Operating Cost. | | | | | |

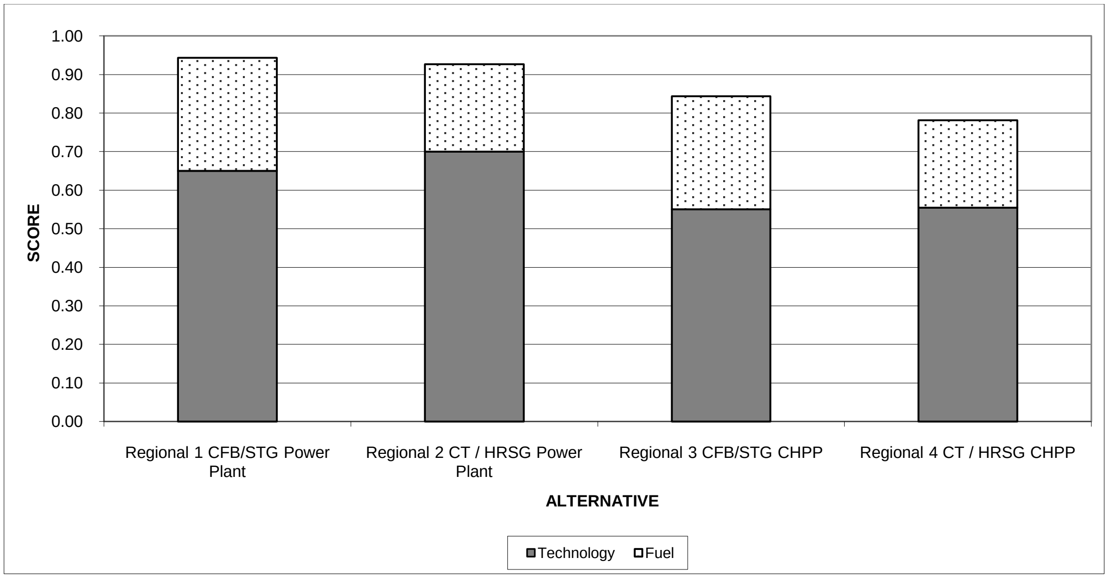



Figure 31. Evaluation score for regional solutions.

The regional power plant alternatives were scored at 7, which is the same score for the installation specific Alternative 1. This was done because a regional power plant is similar to a purchase from GVEA, which is essentially the current situation at FWA.

The regional CHPP Alternatives were scored at 3 because of the reliance on heat from the CHPP. This is seen as a particularly significant issue for FWA.

To test the sensitivity of the ranking to this scoring, a score of 6 was used for the regional alternatives. This higher score for security raised the evaluated scores for Alternatives 3 and 4 from 0.84 and 0.78 to 0.95 and 0.89, respectively, making a new regional coal-fired CHPP the highest scored regional alternative.

### Air and Water Quality

A score of 3 was given to the coal fired Alternative 1 to reflect the relative emissions and high use of water by the Alternative. A score of 10 was given to the oil-fired Alternative 2 because of its reduced emissions and water use.

For the Regional CHPP Alternatives, a score of 5 was given to the coal-fired alternative and a score of 10 to the oil-fired alternative. The higher score for the Regional CHPP reflects the abandonment of the existing CHPPs.

### Cost Stability

The primary influences on cost stability are labor and fuel costs. Labor cost stability is the same across all alternatives. Fuel costs for coal are expected to be very stable. For that reason, the coal alternatives were scored at 10.

Fuel oil costs are determined by world political events and as a result may have a high degree of volatility. For this reason, the fuel oil alternatives were scored 5, particularly in comparison to coal.

### Impact on Alaska Infrastructure

In terms of positive affects on Interior Alaska infrastructure, the military power plants represent one of the major markets for UCM. Without these coal sales, the Mine would have a significantly smaller market. Whether the sales could be replaced with sales elsewhere is unknown. The coal is transported by the Alaska Railroad and is a significant revenue source for it.

The use of the GVEA transmission system to transmit power is not a significant issue for GVEA except to the extent it would need to upgrade its system. In this respect, the expanded use of the GVEA system would help GVEA to reinforce its system locally to serve the installations. To the extent military load is placed on GVEA, it would cause GVEA to add new generation to its system.

Because of the coal mine and railroad considerations, the coal alternatives were scored at 8.

The fuel oil alternatives were scored at 6. Significant benefits to Alaskan infrastructure from using fuel oil have not been identified.

### Water and Solid Waste Reduction

The coal burning alternatives were scored relatively low for this criterion, 3, to reflect the comparatively significant use of water and generation of ash for disposal. The use of CFBs results in additional solid waste in the form of spent limestone. For this reason, these alternatives were scored at 4.

The fuel oil alternatives were scored at 10 to reflect the comparatively small amounts of water used and minimal solid waste. Figure 32 summarizes the scoring and evaluation for the regional alternatives.

## Evaluation of FWA and EAFB Alternatives

For evaluation purposes, the alternatives at FWA were evaluated against each other, as were those for EAFB and for the Regional alternatives. Because several of the alternatives evaluated are similar, the score for a given criterion across several alternatives might be the same. The alternatives involving continued operation of the FWA and EAFB CHPPs had very similar scores. Tables 59 and 60 summarize the evaluation.

### Security

Security for the continued operation of the FWA or EAFB CHPP, Alternatives 1: Repair Only, was given a score of 7 to reflect redundant equipment, recently repaired, providing what has historically been a good level of security. Alternatives 2: Upgrade adds additional STG capacity and was given a score of 8 because of the improved ability to meet electrical loads with onsite generation. Alternatives 3: Follow the Heat Curve received the same score as Alternative 1; the equipment is the same. EAFB Alternative 4 was scored a 9 because the two new boilers and the abandonment of two old boilers would provide improved reliability and redundancy.

Alternatives 5 were given a 10 for security because each would be a new installation with redundant equipment and within the installation fence under direct control of the installation. The use of coal also contributes to the alternatives' security. The fuel oil alternatives were scored 9 in comparison to coal because of the exposure to interruption of the supply to the installation.

### Air and Water Quality

Given continued use of the CHPPs, a score of 4 was given to Alternative 1. Alternative 2 was scored at 7.00 because of the need to retrofit emissions controls. Alternative 3 was scored at 5 because of the reduced fuel consumption in comparison to Alternative 1. EAFB Alternative 4 was scored the same as Alternative 2. Alternative 5 was scored at 7 because of improved emissions controls and efficiency, but less than Alternative 6 at 9 because of the use of oil.

### Cost Stability

The primary influences on cost stability are labor and fuel costs. Labor cost stability is the same across all alternatives. Fuel costs for coal are expected to be very stable. For that reason, the coal alternatives were scored at 10.

Fuel oil costs are determined by world political events and as a result may have a high degree of volatility. For this reason, the fuel oil alternatives were scored 5, particularly in comparison to coal.

### Impact on Alaska Infrastructure

In terms of positive effects on Interior Alaska infrastructure, the military power plants represent one of the major markets for UCM. Without these coal sales, UCM would have a significantly smaller market. Whether the sales could be replaced with sales elsewhere is unknown. The coal is transported by the Alaska Railroad and is a significant revenue source for it.

The use of the GVEA transmission system to transmit power is not a significant issue for GVEA except to the extent it would need to upgrade its system. In this respect, the expanded use of the GVEA system by the FWA and EAFB installations would help GVEA to reinforce its system locally to serve the installations. To the extent military load is placed on GVEA, it would cause GVEA to add new generation to its system.

Because of the coal mine and railroad considerations, the coal alternatives were scored at 8.

The fuel oil alternatives were scored at 6. Significant benefits to Alaskan infrastructure from using fuel oil have not been identified.

### Water and Solid Waste Reduction

Alternatives 1 and 2 were scored at 3 to reflect the use of coal and comparative high use of water and generation of ash. Alternatives 3 and 5 and EAFB Alternative 4 were scored slightly higher at 4 to reflect the reduced coal consumption and increased fuel efficiency. The oil-fired Alternative 6 was scored at 10.

### Alternatives Ranking

Table 59 lists the scoring for the FWA alternatives. The data in Table 60 and Figure 30 show the same information for EAFB. Figures 32 and 33 summarize the information.

From the tables and figures, it can be seen that the highest ranked Alternative for both FWA and EAFB is a new coal-fired CFB and STG CHPP, with a weighted score of 0.99.

For FWA, the three "Repair" alternatives have essentially the same weighted score of 0.91/0.92. The new oil-fired CHPP has a score of 0.89.

For EAFB, the current plan of EAFB to install two new boilers and an STG received the second highest weighted score at 0.95. The other alternatives have essentially the same score, 0.90 to 0.91.

Table 59. Alternatives evaluation matrix—Fort Wainwright.

| Criteria | Weighting | Heat and Power | | | | |
|---|---|---|---|---|---|---|
| | | FWA 1 Repair Only | FWA 2 Repair and Upgrade | FWA 3 Follow Heat Curve | FWA 5 New CFB/ STG CHPP | FWA 6 New CT/ HRSG CHPP |
| | | Coal | Coal | Coal | Coal | Oil |
| Life-Cycle Cost | 30% | 10.00 | 9.40 | 9.80 | 9.80 | 9.30 |
| Security | 40% | 7.00 | 8.00 | 7.00 | 10.00 | 9.00 |
| Capital Cost | 7% | 10.00 | 6.20 | 9.80 | 4.60 | 5.80 |
| Air and Water Quality | 5% | 4.00 | 7.00 | 5.00 | 7.00 | 9.00 |
| Cost Stability | 5% | 10.00 | 10.00 | 10.00 | 10.00 | 5.00 |
| Impact on Alaska Infrastructure | 5% | 8.00 | 8.00 | 8.00 | 8.00 | 6.00 |
| Water and Solid Waste Reduction | 5% | 3.00 | 3.00 | 4.00 | 4.00 | 10.00 |
| Operating Cost | 3% | 8.30 | 8.50 | 8.10 | 10.00 | 8.60 |
| Total | 100% | | | | | |
| Weighted ALTERNATIVE Score | | 8.00 | 8.11 | 8.02 | 9.01 | 8.55 |
| Index to Highest Score | | 0.89 | 0.90 | 0.89 | 1.00 | 0.95 |
| ALTERNATIVE Weighting | 70% | 0.62 | 0.63 | 0.62 | 0.70 | 0.66 |
| Indexed FUEL Score | | 0.98 | 0.98 | 0.98 | 0.98 | 0.76 |
| FUELS Weighting | 30% | 0.29 | 0.29 | 0.29 | 0.29 | 0.23 |
| OVERALL Ranking | | 0.91 | 0.92 | 0.92 | 0.99 | 0.89 |
| All criteria are evaluated qualitatively except Life-Cycle Cost, Capital Cost, and Operating Cost. | | | | | | |

Table 60. Alternatives evaluation matrix—Eielson Air Force Base.

| | | Heat and Power | | | | | |
|---|---|---|---|---|---|---|---|
| | | EAFB 1 Repair Only | EAFB 2 Repair and Upgrade | EAFB 3 Follow Heat Curve | EAFB 4 Upgrade w/ CFB/STG CHPP | EAFB 5 New CFB/ STG CHPP | EAFB 6 New CT/ HRSG CHPP |
| Criteria | Weighting | Coal | Coal | Coal | Coal | Coal | Oil |
| Life-Cycle Cost | 30% | 9.50 | 8.70 | 9.00 | 9.50 | 9.90 | 10.00 |
| Security | 40% | 7.00 | 8.00 | 7.00 | 9.00 | 10.00 | 9.00 |
| Capital Cost | 7% | 10.00 | 3.90 | 9.30 | 3.40 | 2.60 | 4.10 |
| Air and Water Quality | 5% | 4.00 | 7.00 | 5.00 | 7.00 | 7.00 | 9.00 |
| Cost Stability | 5% | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 5.00 |
| Impact on Alaska Infrastructure | 5% | 8.00 | 8.00 | 8.00 | 8.00 | 8.00 | 6.00 |
| Water and Solid Waste Reduction | 5% | 3.00 | 3.00 | 4.00 | 4.00 | 4.00 | 10.00 |
| Operating Cost | 3% | 7.90 | 7.80 | 7.40 | 8.80 | 10.00 | 9.10 |
| Total | 100% | | | | | | |
| Weighted ALTERNATIVE Score | | 7.84 | 7.72 | 7.72 | 8.40 | 8.90 | 8.66 |
| Index to Highest Score | | 0.88 | 0.87 | 0.87 | 0.94 | 1.00 | 0.97 |
| ALTERNATIVE Weighting | 70% | 0.62 | 0.61 | 0.61 | 0.66 | 0.70 | 0.668 |
| Indexed FUEL Score | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.76 |
| FUELS Weighting | 30% | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.23 |
| OVERALL Ranking | | 0.91 | 0.90 | 0.90 | 0.95 | 0.99 | 0.91 |
| All criteria are evaluated qualitatively except Life-Cycle Cost, Capital Cost, and Operating Cost. | | | | | | | |

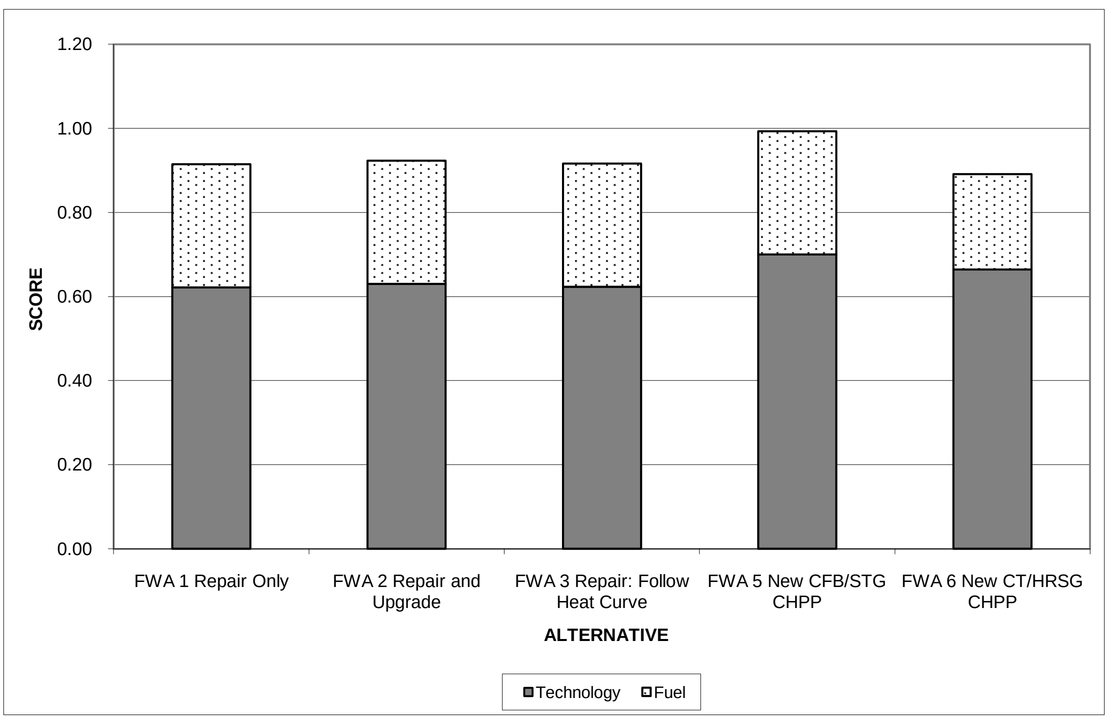



Figure 32. Evaluation score for Fort Wainwright alternatives.

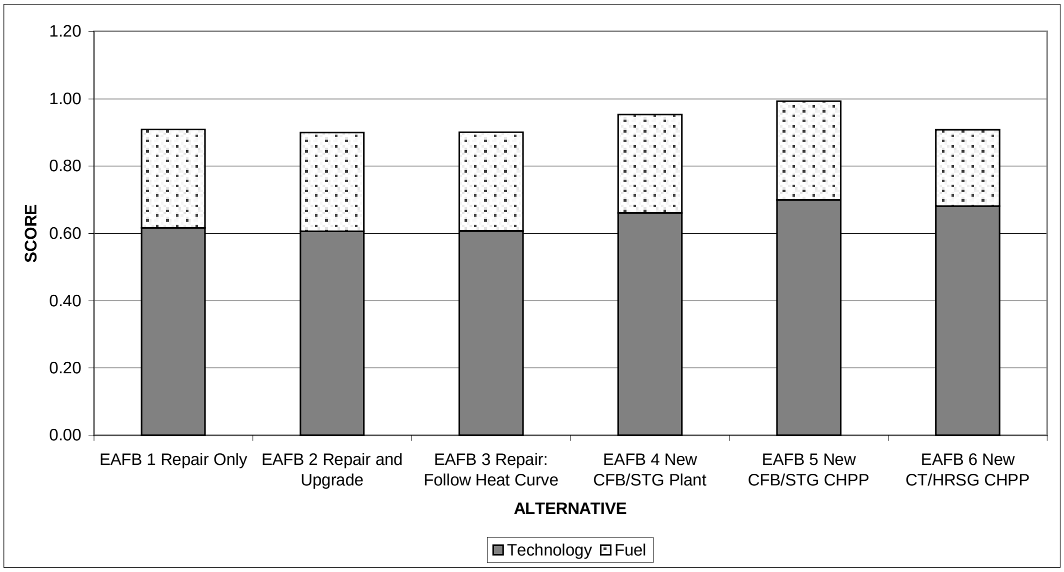



Figure 33. Evaluation score for EAFB alternatives.

## DPO-MA and MAOC Review

The Defense Program Office for Mission Assurance (DPO-MA) and the Mission Assurance Operations Center (MAOC) reviewed the alternatives from a risk assessment perspective. The assessment did not include operational reliability or look at capital or operational expenses.

The review offered the following excerpted observations:

> "Using a central facility to provide either electricity only or both electricity and heat may be an attractive alternative to reduce cost by consolidating the operations; however, both Fort Wainwright and Eielson AFB will be subject to losing their primary source of energy from a single point of failure. An off-base facility will not be enclosed within the secure area of either base, increasing the vulnerability of the facility to malicious attacks. The electric lines and heat pipes connecting the facilities present additional vulnerabilities. Because of the reliance of the two facilities on a single asset, the cumulative risk for both facilities losing their primary source of energy is greater under the regional plant alternatives than installation-specific alternatives."

> "The most significant factor affecting the reliability of operations from external factors is the reliability of delivering the fuel and the physical protection of the asset. Since all alternatives use similar transportation modes to each facility, the differences between the alternatives from a risk assessment perspective are negligible. However, preference should

> be given to fuels that are available from multiple sources. Maintaining a large reserve of fuel at each location would mitigate the risk of transportation interruptions. If natural gas becomes available, using natural gas with petroleum backup would allow diversity in the fuel delivery transportation mode, thereby reducing the risk of fuel disruption."

> "Availability of spare parts and skilled workers to repair and maintain the facility should be considered. Generally, newer and more technologically advanced installations require specialized and proprietary components that are difficult to obtain and specialized craft workers that may be difficult and expensive to hire. Installing proven equipment that is used in many applications, such as conventional fossil-fueled boilers, reduces the technical risk."

> "The installation-specific alternatives are recommended over regional power plant alternatives from a risk assessment perspective. The installation-specific facilities should use proven technologies and fuel diversity."

Although fuel diversity is preferable to reliance on a single fuel, fuel oil is delivered to the area over a single pipeline that is potentially subject to interruption. Natural gas would be subject to the same single-pipeline exposure. Coal, while perceived less favorably from an environmental perspective, is available in abundance, is relatively inexpensive, can be delivered by rail or truck, and can easily be stored in large quantities onsite.

## Comparison of All Alternatives

As discussed in the life-cycle cost analysis, to properly compare the Regional Alternatives with on-installation alternatives, the installation alternatives need to be combined and then compared against the regional alternatives (Table 61 and Figure 34). Figure 34 shows that new coal-fired CFB/STG CHPPs is the highest rated alternative at FWA and EAFB (Alternatives 5).

This is the result of the weighting and scoring for:

- security, both with respect to fuel and the Alternative itself
- availability/Reliability for the fuel
- cost factors (Life-Cycle Cost, Capital Cost, and Operating Cost)
- cost Stability for both fuel and operating costs.

Coal is evaluated as more secure, available, and cost stable than oil. The on-installation alternatives are evaluated as more secure than the regional alternatives. The installation-specific alternatives have lower life-cycle costs than the regional alternatives. The operating costs are lower for the coal-fired alternatives. The coal-fired alternatives were scored low on the environmental criteria.

From Figure 34, it can be seen that the next ranked alternatives are the installation-specific alternatives. The four Regional Alternatives' evaluation scored them lower than the installation-specific alternatives. The power plant alternatives scored higher than the CHPP alternatives because of Security scoring for heat.

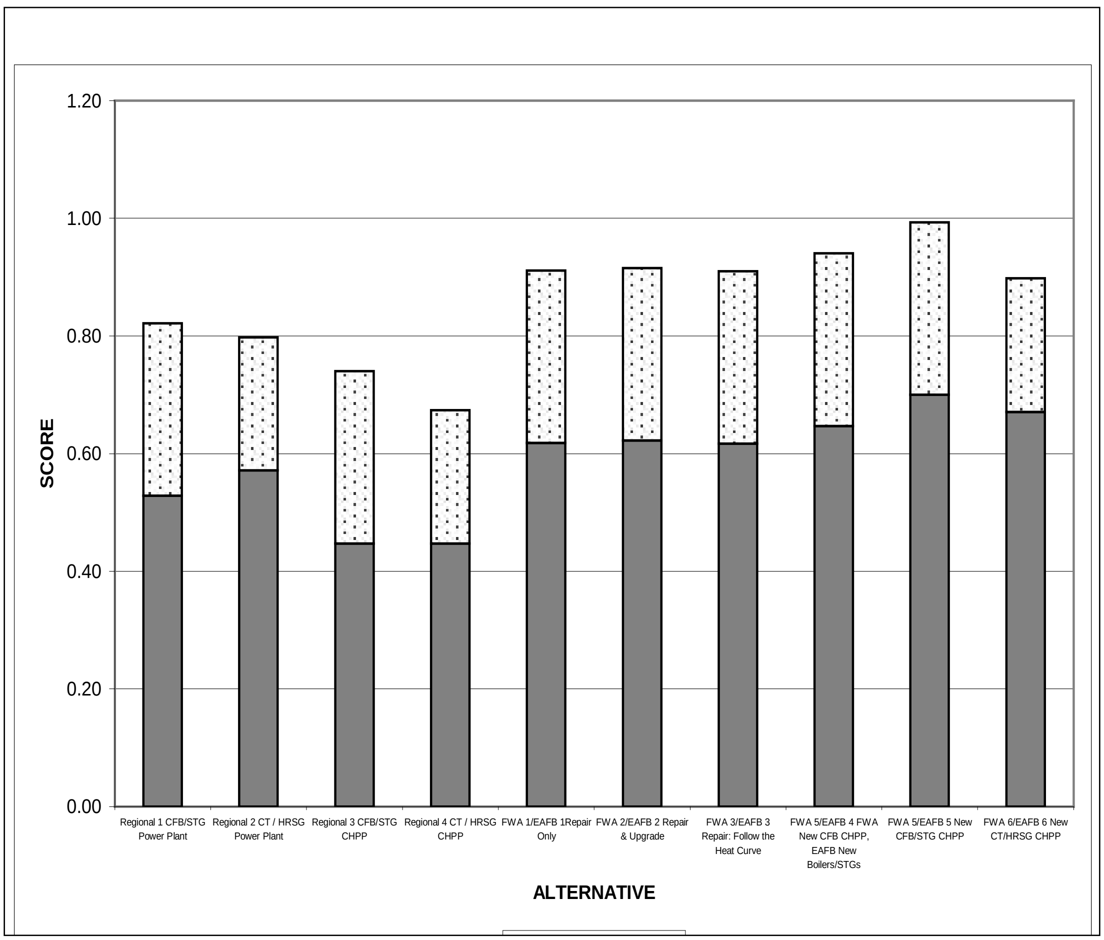



Figure 34. Overall evaluation scores

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Table 61. Regional alternatives and installation alternatives combinations / alternatives evaluation matrix.

| | | REGIONAL ALTERNATIVES | | | | COMBINATIONS OF FWA AND EAFB ALTERNATIVES | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Electricity Only | | All Heat and Power | | Heat and Power | | | | | |
| | | Regional 1 CFB/STG Power Plant | Regional 2 CT/HRSG Power Plant | Regional 3 CFB/STG CHPP | Regional 4 CT/HRSG CHPP | FWA 1/ EAFB 1 Repair Only | FWA 2/ EAFB 2 Repair and Upgrade | FWA 3/ EAFB 3 Repair: Follow the Heat Curve | FWA 5/EAFB 4 FWA Repair and Upgrade, EAFB CFB/ STG | FWA 5/ EAFB 5 New CFB/ STG CHPP | FWA 6/ EAFB 6 New CT/ HRSG CHPP |
| Criteria | Weighting | Coal | Oil | Coal | Oil | Coal | Coal | Coal | Coal | Coal | Oil |
| Life-Cycle Cost | 30% | 7.50 | 7.90 | 8.90 | 8.10 | 9.90 | 9.30 | 9.60 | 9.80 | 10.00 | 9.70 |
| Security | 40% | 7.00 | 7.00 | 3.00 | 3.00 | 7.00 | 8.00 | 7.00 | 8.50 | 10.00 | 9.00 |
| Capital Cost | 7% | 4.40 | 5.50 | 3.20 | 4.50 | 10.00 | 5.40 | 9.70 | 4.20 | 3.90 | 5.30 |
| Air and Water Quality | 5% | 3.00 | 10.00 | 6.00 | 10.00 | 4.00 | 7.00 | 5.00 | 7.00 | 7.00 | 9.00 |
| Cost Stability | 5% | 10.00 | 6.00 | 10.00 | 6.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 5.00 |
| Impact on Alaska Infrastructure | 5% | 8.00 | 6.00 | 8.00 | 6.00 | 8.00 | 8.00 | 8.00 | 8.00 | 8.00 | 6.00 |
| Water and Solid Waste Reduction | 5% | 4.00 | 10.00 | 4.00 | 10.00 | 3.00 | 3.00 | 4.00 | 3.50 | 4.00 | 10.00 |
| Operating Cost | 3% | 6.80 | 6.90 | 9.10 | 7.40 | 8.30 | 8.40 | 8.00 | 9.50 | 10.00 | 8.90 |
| Total | 100% | | | | | | | | | | |
| Weighted ALTERNATIVE Score | | 6.81 | 7.36 | 5.77 | 5.77 | 7.97 | 8.02 | 7.95 | 8.34 | 9.02 | 8.65 |
| Index to Highest Score | | 0.75 | 0.82 | 0.64 | 0.64 | 0.88 | 0.89 | 0.88 | 0.92 | 1.00 | 0.96 |
| ALTERNATIVE Weighting | 70% | 0.53 | 0.57 | 0.45 | 0.45 | 0.62 | 0.62 | 0.62 | 0.65 | 0.70 | 0.67 |
| Indexed FUEL Score | | 0.98 | 0.76 | 0.98 | 0.76 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.76 |
| FUELS Weighting | 30% | 0.29 | 0.23 | 0.29 | 0.23 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.23 |
| OVERALL Ranking | | 0.82 | 0.80 | 0.74 | 0.67 | 0.91 | 0.92 | 0.91 | 0.94 | 0.99 | 0.90 |

The order of ranking from highest to lowest is:

| Evaluated Score | Alternative |
|---|---|
| 0.99 | New coal-fired CHPPs at FWA and EAFB |
| 0.94 | New coal-fired CHPP at FWA and New boilers at EAFB |
| 0.92 | Repair and add STG capacity at FWA and EAFB |
| 0.91 | Repair the FWA and EAFB CHPPs |
| 0.91 | Repair and operate as fuel efficiently as possible |
| 0.90 | New oil- or natural gas-fired CHPPs at FWA and EAFB |
| 0.82 (0.76) | New regional coal-fired CHPP |
| 0.80 (0.74) | New regional coal-fired power plant |
| 0.74 (0.72) | New regional oil or natural gas-fired power plant |
| 0.67 (0.61) | New regional oil or natural gas-fired CHPP |

Table 62 lists the various alternatives with regard to major technical, economic, and environmental parameters.

## Sensitivity Analysis

Table 63 lists the weightings of the various evaluation criteria for fuels and for the alternatives. Using the evaluation weightings of 30 percent for fuel and 70 percent for the alternative, it can be seen in the right-most column that Security represents the single most important criterion, 34 percent, followed by the various Cost factors (life-cycle cost, capital cost to Federal government, operating costs) at 28 percent. Environmental factors (air and water quality, water and solid waste reduction) represent 13 percent of the weighting. Availability/Reliability of the fuel represents 12 percent of the weighting.

Security, Cost, fuel Availability/Reliability, and Cost Stability represent 84 percent of the weighted evaluation. As evaluated, coal and coal-fired alternatives scored higher than oil-fired alternatives for Security, Life-Cycle Cost, fuel Availability/Reliability, and Impact on Alaska Infrastructure. Oil and oil-fired alternatives scored higher for Capital Cost and Environmental Criteria.

Table 62. Summary of evaluated alternatives' key parameters.

| Category | Technical | | | Economic | | | | Environmental | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel Source | | | 25-Year Life-Cycle Costs (Millions) | NPV Alternative Capital Costs (Millions) | NPV Annual O&M (Millions) | 25-Year Average No. of FTEs | 2015 Annual Estimated Controlled Emissions (tons per year)[2] | | | | |
| Alternative Description | Primary | Alternate | Security[1] | | | | | NOx | $SO_2$ | CO | PM | VOC |
| REGIONAL ALTERNATIVES | | | | | | | | | | | | |
| 1 Coal-fired power generation only | Coal | Oil | 7 | $1,492.6 | $233.9 | $1,258.7 | 45 | 1,911.8 | 1,382.9 | 3,924.2 | 31.9 | 16.8 |
| 2 Oil-fired generation only | Oil | Naphtha | 7 | $1,416.2 | $186.2 | $1,230.0 | 36 | 1,471.4 | 1,360.1 | 820.9 | 30.2 | 8.5 |
| 3 Coal-fired CHPP with long-distance heat transmission | Coal | Oil | 3 | $1,261.7 | $324.7 | $936.9 | 50 | 708.4 | 357.8 | 4,636.8 | 6.2 | 12.9 |
| 4 Oil-fired CHPP with long-distance heat transmission | Oil | Naphtha | 3 | $1,383.5 | $226.4 | $1,157.2 | 41 | 126.2 | 796.3 | 16.0 | 31.5 | 1.1 |
| INSTALLATION-SPECIFIC ALTERNATIVES | | | | | | | | | | | | |
| *FWA* | | | | | | | | | | | | |
| 1 Repair existing CHPP, no added capacity | Coal | N/A | 7 | $566.3 | $78.7 | $487.6 | 58 | | | | | |
| 2 Repair existing CHPP, upgrade STG capacity | Coal | N/A | 8 | $604.7 | $127.7 | $477.0 | 58 | Combined with EAFB | | | | |
| 3 Repair existing CHPP, no added capacity, follow heat curve | Coal | N/A | 7 | $576.6 | $80.1 | $496.6 | 58 | | | | | |
| 5 New plant using CFB | Coal | Oil | 10 | $575.8 | $171.8 | $404.0 | 46 | | | | | |
| 6 CT cogeneration (HRSG for heat), liquid fuel | Naphtha | Oil | 9 | $608.0 | $136.6 | $471.5 | 38 | | | | | |
| *EAFB* | | | | | | | | | | | | |
| 1 Repair existing CHPP, no added capacity | Coal | N/A | 7 | $437.3 | $24.2 | $413.1 | 63 | 2,092.7 | 1,670.0 | 1,281.5 | 31.9 | 12.0 |
| 2 Repair existing CHPP, upgrade STG capacity | Coal | N/A | 8 | $477.9 | $62.3 | $415.6 | 63 | 462.7 | 368.1 | 1,314.5 | 34.7 | 13.1 |
| 3 Repair existing CHPP, no added capacity, follow heat curve | Coal | N/A | 7 | $465.0 | $26.0 | $439.1 | 63 | 1,752.1 | 1,406.8 | 1,221.5 | 27.4 | 10.3 |
| 4 Upgrade with new CFB and additional STGs | Coal | Oil | 9 | $439.9 | $70.7 | $369.2 | 56 | 807.7 | 517.9 | 3,022.4 | 15.0 | 10.0 |
| 5 New plant using CFB | Coal | Oil | 10 | $419.5 | $94.7 | $324.8 | 48 | 530.5 | 267.9 | 3,472.2 | 11.6 | 9.6 |
| 6 CT cogeneration (HRSG for heat), liquid fuel | Naphtha | Oil | 9 | $416.3 | $58.9 | $357.3 | 40 | 107.3 | 677.3 | 13.6 | 26.8 | 0.9 |

[1] Security against supply disruption.

[2] Includes estimated emissions related to power purchases from GVEA for Installation-Specific Alternatives 1 and 3.

Table 63. Summary of weighted evaluation criteria.

| Criterion | Fuels Evaluation | Alternatives Evaluation | Weighted (at 30% and 70%) |
|---|---|---|---|
| Security | 20% | 40% | 34% |
| Cost | | 40% | 28% |
| Environmental | 20% | 10% | 13% |
| Availability/reliability | 40% | | 12% |
| Cost stability | 20% | 5% | 10% |
| Infrastructure | | 5% | 4% |
| Total | 100% | 100% | 100% |

To test the effect of the weighting for Security (40 percent) and Life-Cycle Cost (30 percent), the weightings were changed to: Security—20 percent and Life-Cycle Cost—50 percent. This had the effect of increasing the Regional CHPP Alternative scores by 0.06, raising the Regional Coal-Fired CHPP to a score of 0.80 from 0.74. The scores of the installation-specific alternatives that continue operation of the existing CHPPs rose 0.02 to 0.05 to the range of 0.94 to 0.96 from 0.91 to 0.94. The relative rankings were unchanged, however. To get a dramatic change, the environmental criteria weighting would have to be increased dramatically and the Security criterion weighting decreased by the same amount. An increase in the weighting of Air and Water Quality from 5 percent to 35 percent, and a corresponding decrease of Security from 40 percent to 10 percent, increased the score for the Oil-Fired Regional CHPP from 0.67 to 0.87.

The effect of the separate fuels evaluation was evaluated by setting its weighting to 0. The result was to increase the FWA/EAFB oil-fired Alternative 6 from a score of 0.90 to 0.95, making it the second highest ranked alternative.

Based on the above, it would take a combination of significant changes in weightings and scorings for overall alternative rankings to change significantly.

The regional alternatives were scored lower on security issues. The two ways this might change would be to decrease the weighting of Security or increase the scores for the regional alternatives. Increasing the scores to the same scores as the on-site installation specific alternatives would be questionable.

The regional alternatives also scored lower on life cycle costs. Decreasing the weighting for life cycle costs would result in the regional alternatives

receiving higher relative scores. The regional alternatives low ranking is robust. That is, moderate changes to the weightings or scoring results in the regional alternatives do not result in the regional alternatives receiving high ranking.

Shifting the weighting of life cycle costs (from 30 percent to 10 percent) to air and water quality (from 5 percent to 25 percent) results in the oil-fired alternatives receiving somewhat higher evaluated scores. Alternatives 6 at FWA and EAFB become scored at 0.93, compared to 0.98 for Alternatives 5.

# 18 Conclusion

The study concludes that:

- Coal is the most secure fuel available in Interior Alaska.
- Regional solutions are more expensive and less secure than installation-specific solutions.
- Over the study period (2004 to 2028) with new plants coming online in 2012, new coal-fired CHPPs at FWA and EAFB are the highest ranked solutions.
- Because of its location, FGA has no economically justified regional solution. Electricity should be purchased directly from GVEA rather than generated at FWA and transmitted over the GVEA system. After including losses and GVEA transmission charges, it is less expensive to buy directly from GVEA.
- The DOD should participate collectively for the GFMC installations in the local electric utility's (GVEA's) next rate-making process (anticipated to occur in 2005) to ensure that its interests are represented with regard to the demand charge, transmission system use charges, cost allocations, and rate structure.
- Installations should work to participate with GVEA in the pursuit of developing wind energy.
- FWA, FGA, and EAFB should evaluate conversion of their heat distribution systems from steam to hot water, as hot water distribution may be more cost-effective than steam.

The following steps are recommended:

- Develop sufficient project definition to support DD Form 1391 budget level cost estimates for new coal-fired CHPPs at FWA and EAFB and for two new coal-fired CFBs at EAFB.
- Update the life-cycle cost analysis for the DD Form 1391 cost estimates.
- Choose alternative(s) and include them in the appropriate Military Construction program plan.

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# Appendix A: Alaska Federal-Civilian Energy Efficiency Swap Act of 1980

this chapter) shall be referred to as the 'Alaska Federal-Civilian Energy Efficiency Swap Act of 1980'.''

-CITE-
40 USC Sec. 795a 01/02/01

-EXPCITE-
TITLE 40 - PUBLIC BUILDINGS, PROPERTY, AND WORKS
CHAPTER 17A - ALASKA FEDERAL-CIVILIAN ENERGY EFFICIENCY SWAP

-HEAD-
Sec. 795a. Sale of electric energy; contracting authority; required determinations; pricing policies

-STATUTE-
(a) For the purposes of conserving oil and natural gas and better utilizing coal, any agency is authorized to sell to any non-Federal person, and to enter into contracts for the sale to any non-Federal person of, electric energy generated by coal-fired electric generating facilities of such agency in Alaska without regard to any provision of law which precludes such sale where such energy is available from other local sources, if the agency determines that -

(1) such energy is generated by an existing coal-fired generating facility;

(2) such energy is surplus to such agency's needs and is in excess of the electric energy specifically generated for consumption by, or necessary to serve the requirements of, any department, agency, or instrumentality of the United States;

(3) the costs to the ultimate consumers of such energy is less than the costs which, in the absence of such sale, would be incurred by such consumers for the purchase of an equivalent amount of energy; and

(4) such sale will result in a reduction in the total consumption of oil or natural gas by the non-Federal person purchasing such electric energy below that consumption which would occur in the absence of such sale.

(b) Federally generated electric energy sold by an agency as provided in subsection (a) of this section shall be priced to recover the fuel costs and variable operation and maintenance costs of the Federal generating facility concerned which costs are attributable to such sale, plus an amount equal to one-half the difference between -

(1) the costs of producing the electric energy by coal generation, and

(2) the costs of producing electric energy by the oil or gas generation being displaced.

-SOURCE-
(Pub. L. 96-571, Sec. 3, Dec. 22, 1980, 94 Stat. 3341.)

-SECREF-
SECTION REFERRED TO IN OTHER SECTIONS
This section is referred to in section 795c of this title.

-CITE-
40 USC Sec. 795b 01/02/01

-EXPCITE-
TITLE 40 - PUBLIC BUILDINGS, PROPERTY, AND WORKS
CHAPTER 17A - ALASKA FEDERAL-CIVILIAN ENERGY EFFICIENCY SWAP

-HEAD-
Sec. 795b. Purchase of electric power; authority; applicable criteria

-STATUTE-
For purposes of economy and efficiency and conserving oil and natural gas, whenever practicable and consistent with other laws applicable to any agency and whenever consistent with the requirements applicable to any agency, such agency shall endeavor to purchase electric power from any non-Federal person for consumption in Alaska by any facility of such agency where such purchase -

(1) will result in a savings to other consumers of electric energy sold by such non-Federal person without increasing the cost incurred by any agency for electric energy, or

(2) will result in a cost savings to such agency of electric energy without increasing costs to other consumers of electric energy,

taking into account the remaining useful life of any facility available to such agency to generate electric energy for such agency and the cost of maintaining such facility on a standby basis.

-SOURCE-
(Pub. L. 96-571, Sec. 4, Dec. 22, 1980, 94 Stat. 3342.)

-CITE-
40 USC Sec. 795c 01/02/01

-EXPCITE-
TITLE 40 - PUBLIC BUILDINGS, PROPERTY, AND WORKS
CHAPTER 17A - ALASKA FEDERAL-CIVILIAN ENERGY EFFICIENCY SWAP

-HEAD-
Sec. 795c. Implementation powers and limitations

-STATUTE-
(a) Accommodation of needs of non-Federal person for electric energy

Nothing in this chapter shall be construed as requiring or authorizing any department, agency, or instrumentality of the United States to construct any new electric generating facility or related facility, to modify any existing facility, or to employ reserve or standby equipment in order to accommodate the needs of any non-Federal person for electric energy.

(b) Availability of revenues from sales

Revenues received by any agency pursuant to section 795a of this title from the sale of electric energy generated from any facility of such agency shall be available to the agency without fiscal year limitation for the purchase of fuel and for operation, maintenance, and other costs associated with such facility.

(c) Exercise of authorities

The authorities of this chapter shall be exercised for such

ENCl 1

periods and pursuant to such terms and conditions as the agency concerned deems necessary consistent with the provisions of this chapter and consistent with its responsibilities under other provisions of law.

(d) Negotiation and execution of contracts and other agreements

All contracts or other agreements executed under this chapter, notwithstanding any other provision of law, shall be negotiated and executed by the agency selling or purchasing electric energy under this chapter.

-SOURCE-

(Pub. L. 96-571, Sec. 5, Dec. 22, 1980, 94 Stat. 3342.)

-CITE-

40 USC Sec. 795d 01/02/01

-EXPCITE-

TITLE 40 - PUBLIC BUILDINGS, PROPERTY, AND WORKS

CHAPTER 17A - ALASKA FEDERAL-CIVILIAN ENERGY EFFICIENCY SWAP

-HEAD-

Sec. 795d. Repealed. Pub. L. 105-362, title IV, Sec. 401(g), Nov. 10, 1998, 112 Stat. 3282

-MISC1-

Section, Pub. L. 96-571, Sec. 6, Dec. 22, 1980, 94 Stat. 3342; Pub. L. 103-437, Sec. 14(c), Nov. 2, 1994, 108 Stat. 4591, related to biennial reports by Secretary of Energy on action taken by agencies pursuant to this chapter.

-CITE-

CONTRACT FOR SALE OF UTILITIES SERVICES

For use of this form, see AR 420–41; the proponent agency is the Office of the Chief of Enginee

Contract No. DAKF70-81-S-0069

Estimated Annual Cost to Purchaser $ 1,200,000

THIS CONTRACT, entered into this 4th day of May 1
by and between the UNITED STATES OF AMERICA (hereinafter called the "Government"), resented by the Utilities Sales Officer executing this contract and
Golden Valley Electric Association Inc., Box 1249, Fairbanks, AK 99
(Hereinafter called the "Purchaser")

WITNESSETH THAT:
WHEREAS, the Government has established an installation near Fairbanks known as Fort Wainwright, and owns, maintains and operates facilit the furnishing of electrical servic
WHEREAS, the Purchaser desires to obtain electrical service from the Government, as required for resale, and which cannot be readily obtained fro other source; and
~~WHEREAS, construction of facilities in connection with the sale of such service to the Pur will not hinder the construction of public or private utility service facilities of a like natur~~
WHEREAS, pursuant to ~~10 U.S.C. 2481~~ Public Law 96-571 the Government is authorized to sell utility service quired by the Purchaser;
NOW, THEREFORE, in consideration of the premises and the mutual agreement herein cont to be performed by the parties hereto respectively, it is agreed as follows:

## GENERAL PROVISIONS

1. SERVICES TO BE RENDERED. From and after the effective date of this contract, the Government will furnish, subject to the limitations hereinafter provided, and the Purchaser receive and pay for such utility services as described in Special Provisions A(S), Elec Service attached hereto and made a part hereof.

2. PAYMENTS. For and in consideration of the performance of the stipulations of this cor the Purchaser shall pay the Government for service herein contracted for, at the rates and u the terms and conditions set forth in attached Special Provisions.

3. USE OF SERVICE. The Government, by reason of this contract, is not obligated to per ently supply the Purchaser with utility service. The service described herein is temporaril supplied as an accommodation to Purchaser as the Government service is presently availab ~~service is not otherwise readily obtainable by the Purchaser~~, and the furnishing of such se under the existing conditions is deemed to be in the public interest. Purchaser's use of su service is limited to such time as service can be supplied by the Government as surplus to own needs, the Government has facilities and personnel available to supply the service an ~~service is not readily available to the Purchaser from another source~~. Purchaser shall use services provided herein in such a manner as not to in any way disrupt or interfere with the requirements of the Government or any other Purchaser that may be served by the Governme ~~Such services shall be for use by Purchaser and shall not be purchased for resale.~~

4. CHANGE OF RATES. (REVISED) The rates for service to be charged the Purchaser shall at all times produce a revenue which is not less than t Cost to the Government of supplying the service, including variable ope and maintenance costs plus an amount equal to one-half the difference b the Government costs and the cost of producing electric energy by the c gas generation being displaced. If during the life of this contract, t should be an appreciable change in the costs, the contract rates set fc herein will be adjusted as required to conform therewith and the Govern agrees to furnish, subject to the conditions set forth herein, and Purc agrees to take and pay for, such service at the adjusted rates from and the date when such adjusted rates are made effective. The rates and ch

5. LIABILITY. The Purchaser shall hold and save the Government, its officers, agents and employees, harmless from liability of any nature or kind, for or on account of any claim or acti that may be asserted in connection with the services furnished under this contract. The Gover ment will not be held liable for failure to provide continuous service and will not guarantee quality or quantity of service to be supplied nor will the Government be made liable for termin tion of services.

6. TERMINATION. Services under this contract may be terminated by either party by written notice not less than thirty days in advance of the effective date of termination; provided that i the event of a national emergency proclaimed by the President, the Government may terminate this contract immediately without such advance notice. It is further mutually agreed that this contract will be terminated at such time as:

- ~~a. The ser[illegible] contemplated herein becomes readily available from another source, or~~
- b. The installation furnishing said service becomes inactive, or
- c. The Government no longer has facilities and/or personnel available to supply the servic
- d. The Government can no longer supply such service as surplus to its own needs.

7. RECAPTURE. In the event this contract is terminated in accordance with the terms hereof, the Government shall have the right to recapture immediately any utility facility it may have furnished in connection with the sale of any utility service to the Purchaser.

8. FACILITIES TO BE PROVIDED. The Government shall not be obligated in any way for the cost of making connections for Purchaser's service. Purchaser shall at Purchaser's expense, install, maintain and operate all new facilities required for obtaining service, including suitabl metering and regulating equipment and service connections to Government's utility system. Plans for all such facilities shall be subject to the approval of the Utilities Sales Officer and the installation of such facilities shall be subject to his supervision.

9. LICENSE FOR FACILITIES. The Government hereby grants to the Purchaser a license to enter upon and use a site or sites to be agreed upon between the parties hereto upon which the Purchaser shall install, operate and maintain the Purchaser's new facilities to be located on Government property for obtaining service; and such license shall continue in effect until termination of this contract. Facilities installed by the Purchaser on a Government installation will be removed promptly at the expense of the Purchaser upon termination of the service contemplated herein. Government land and facilities will be restored to their original condition at the expense of the Purchaser. If the Purchaser fails to so remove such facilities within ninety (90) days they will be deemed to be abandoned and become Government property.

*applicable to the service or services contemplated herein will be revi annually, or more often if necessary, in compliance with the above requ

10. OFFICIALS NOT TO BENEFIT. No member of or delegate to Congress or resident commissioner shall be admitted to any share or part of this contract or to any benefit that m arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

11. COVENANT AGAINST CONTINGENT FEES. The Purchaser warrants that no person selling agency has been employed or retained to solicit or secure this contract upon an ag ment or understanding for a commission, percentage, brokerage, or contingent fee, exceptir bona fide employees or bona fide established commercial or selling agencies maintained b Purchaser for the purpose of securing business. For breach or violation of this warranty t Government shall have the right to annul this contract without liability or in its discretion require the Purchaser to pay, in addition to the contract price or consideration, the full am of such commission, percentage, brokerage, or contingent fee.

12. DISPUTES. (a) Except as otherwise provided in this contract, any dispute concernin question of fact arising under this contract which is not disposed of by agreement shall be decided by the Utilities Sales Officer, who shall reduce his decision to writing and mail o otherwise furnish a copy thereof to the Purchaser. The decision of the Utilities Sales Off shall be final and conclusive unless, within 30 days from the date of receipt of such copy, Purchaser mails or otherwise furnishes to the Utilities Sales Officer a written appeal addr to the Secretary. The decision of the Secretary or his duly authorized representative for th determination of such appeals shall be final and conclusive unless determined by a court c competent jurisdiction to have been fraudulent, or capricious, or arbitrary, or so grossly er eous as necessarily to imply bad faith, or not supported by substantial evidence. In conne with any appeal proceeding under this clause, the Purchaser shall be afforded an opportun to be heard and to offer evidence in support of its appeal. Pending final decision of a dis hereunder, the Purchaser shall proceed diligently with the performance of the contract and accordance with the Utilities Sales Officer's decision.

(b) This "Disputes" clause does not preclude consideration of law questions in conr tion with decisions provided for in paragraph (a) above: Provided, That nothing in this co tract shall be construed as making final the decision of any administrative official, repres -tive, or board on a question of law.

13. Energy will be furnished under this contract only when

(a) such energy is generated by an existing coal-fired generatir facility;

(b) such energy is surplus to such agency's needs and is in exce of the electric energy specifically generated for consumption by, o necessary to serve the requirements of, any department, agency, or instrumentality of the United States;

(c) the costs to the ultimate consumers of such energy is less than the costs which, in the absence of such sale, would be incurre by such consumers for the purchase of an equivalent amount of energ and

(d) such sale will result in a reduction in the total consumpti of oil or natural gas by the non-Federal person purchasing such electric energy below that consumption which would occur in the abs

14. DEFINITIONS. As used throughout this contract, the following terms shall have th ings set forth below:

a. The term "Secretary" means the Secretary, the Under Secretary, or any Assista Secretary of the Department, and the head or any assistant head of the Federal agency; term "his duly authorized representative" means any person or persons or board (other t Utilities Sales Officer) authorized to act for the Secretary.

b. The term "Utilities Sales Officer" means the person executing this contract on of the Government, and any other officer or civilian employee who is a properly designat Utilities Sales Officer; and the term includes, except as otherwise provided in this conti the authorized representative of a Utilities Sales Officer acting within the limits of his authority.

15. See Below.

IN WITNESS WHEREOF, the parties hereto have executed this contract as of the day and first above written.

THE UNITED STATES OF AMERICA

By

L.J. BONITO, Colonel, CE

Repair and Utilities Sales Off

(Official Title)

(Purchaser)

R. L. Hufman, General Ma

Golden Valley Electric A

P.O. Box 1249
Fairbanks, AK 99707

(Business Address)

15. This contract shall be subject to the written approval of the Army Power Procurement Officer or his duly authorized representati and shall not be binding until approved.

APPROVED LAMUTT 2

ARMY POWER PROCUREME
OFFICER REPRESENTATI
US ARMY FORCES COMM

Attached to and made
- a part of Contract No. DAKF70-81-S-00

SPECIAL PROVISIONS A (S)
ELECTRIC SERVICE
For use of this form, see AR 420–41; the proponent agency is the Office of the Chief of Engineer

1. ESTIMATED SERVICE REQUIREMENTS.

Estimated Maximum Demand 5,000 kw
Estimated annual consumption 20,000,000 kwh
(The parties hereto are not obligated to deliver or receive, nor are they restricted to, the ab amounts.)

2. POINT OF DELIVERY. The point of delivery of service shall be
at Fort Wainwright plant 3595, 12.5KV switchgear

3. DESCRIPTION OF ELECTRIC SERVICE. The Government will supply 3 phase, 4 wire 60 cy alternating current at 7,200/12,470 volts.

4. RATES. The rates to be charged the Purchaser by the Government for the electric servi described herein, are as follows: will be one-half the sum of $0.0418/KWH (from EXHIBIT A) plus the cost of producing electric energy by the oi or gas generation being displaced (from EXHIBIT B). Prior to each billing, the authorized representatives of the parties sh meet to establish the billing parameters, i.e., fuel cost and heat rates for generation units displaced in accordar with Exhibit B.

5. METERING AND BILLING. Service will be measured at 7,200/12,470 by 1 watt–hour meter(s) and demand meter(s) to be furnished, installed and maintained by the Purchaser. The meter(s) be read by the Utilities Sales Officer, or his authorized representative, and bills will be re monthly to the Purchaser by the Government. All such bills will be due and payable 15 da after receipt thereof by the Purchaser.

6. ALTERATIONS AND ADDITIONS:

a. Computation of Costs and Charges, Steam and Electric Power P 3595, Fort Wainwright, Alaska (EXHIBIT A) is attached hereto and ma a part hereof.

b. GVEA computations (EXHIBIT B) is attached hereto and made a hereof.

SHEET 1 of 2

| | | | |
|---|---|---|---|
| Lee Slick | DATE 28 Jan 81 | PERIOD | FY 80 |

PRODUCTION DATA

| | | | | |
|---|---|---|---|---|
| ıM GENERATION | | 18 | ELECTRIC GENERATION | |
| ıty Generated | lb. | 19 | Gross Generation | 74,359 |
| ge Temperature | °F | 20 | Net Energy Exported | 62,623 |
| ge Pressure | psig | 21 | Station Service and Losses | 11,736 |
| ɔy | Btu/lb | 22 | CONDENSATE | |
| PSIG HEATING STEAM | | 23 | Quantity from Condensers | 665,615 |
| ty Exported | lb. | 24 | Quantity Returned from Base | |
| ge Temperature | °F | 25 | Ave. Temp. of Heating Returns. | |
| ge Pressure | psig | 26 | Enthalpy of Heating Returns | |
| py | Btu/lb | 27 | MAKEUP WATER | |
| PSIG PROCESS STEAM | | 28 | Gross Makeup to Treatment | |
| ty [illegible]ted | lb. | 29 | Initial Temperature | |
| ge Temperature | °F | 30 | Initial Enthalpy | |
| ge Pressure | psig | 31 | Net Makeup to Steam Cycle | |
| py | Btu/lb | 32 | | |
| | | 33 | | |
| | | 34 | | |

FUEL (COAL)

| | | | | |
|---|---|---|---|---|
| Boilers (2000 lbs) | Tons | 38 | Input to Boilers ($25 \times 10^6$ Btu) | |
| Heating Value | Btu/lb | 39 | Total Thermal Value | |
| ost $ | | 40 | Cost per $10^6$ Btu | $ |

FUEL COST ALLOCATION

| | |
|---|---|
| ıl Value of Gross Generation (19) x 3690 = | 274,384 |
| ser Heat Rejection (23) x 935 = | 622,350 |
| eration Ratio $\frac{(20)}{(19)}$ = | 0.842 |
| Charged to Electric Generation (43) [(41) + (42)] = | 755,260 |
| Return Ratio $\frac{(24)}{(7)+(12)}$ or $\frac{(7)+(12)-(31)}{(7)+(12)}$ = | |
| ed Return Enthalpy {(45) [(26) - (30)]} + (30) = | |
| Charged to Heating Steam (7) [(10) - (46)] = | / |
| Charged to Process Steam (12) [(15) - (46)] = | |
| ergy Charged to Steam (47) + (48) = | 1,426,217 |
| of Fuel Cost to Steam $\frac{100 \times (49)}{(44)+(49)}$ = | 65.4 |
| st Allocated to Steam $\frac{(50) \times (37)}{100}$ = $ | |
| of Fuel Cost to Electricity 100 - (50) = | 34.6 |
| st Allocated to Electricity $\frac{(52) \times (37)}{}$ = $ | |

| | |
|---|---|
| :ondensing Generation: (Page V-4 of R. W. Beck shows 258.1 Btu/lb steam ›90 Btu/KWH or 3690/258.1 = 14.3 lb/KWH) (23)/14.3 = | 46,546 MWH |
| loncondensing Electrical Generation (19) - (54) = | 27,812 MWH |
| :nergy Charged to Noncondensing Generation (55) x 3.69 = | 102,626 MBTU |
| :atio of Condensing to Total Generation Energy 1 - ((56) / (41) + (42)) = | 0.886 |
| ercent of Fuel Charged to Condensing Generation (57) x (52) = | 30.7 |
| uel (Coal) | 169,530 Ton |
| u[illegible]Cost (59) x (58)/100 x $28.26/Ton | $1,470,812 |
| ondensing Unit Fuel Cost (60)/((54) x (43)) | $0.0375/KWH |
| aintenance Unit Cost K1310/(20) + (K1310 Labor x .04)/(20) | $0.0031/KWH |
| ncremental Unit Cost (61) + (62) | $0.0406/KWH |
| ate (incl 3% OH) (63) x 1.03 | $0.0418/KWH |

?530 TON/(46,546 MWH x .842) = 4.326 TON/MWH x.307 x 15.5 K/T

= 20,583 BTU/KWH

NATORY NOTES FOR ITEMS OF COMPUTATION

Dividing the quantity of condensate from the condensers by 14.3 gives the t of electrical energy generated by steam which is condensed. The Beck indicates that the small amount of condensate added by flow through the jectors is effectively cancelled by makeup water heating. See pages V-5 -6 of Beck study.

Self-explanatory.

The energy charged to noncondensing generation is the 3960 Btu/KWH as lished by the Beck report and is as used in (41).

The ratio of total energy charged to electric generation (one) less the of energy for noncondensing generation (55) divided by the total energy eration (41) + (42) is the ratio of condensing to total generation energy.

Product of ratio of condensing to total generation (57) and ratio of generat tal (52) is the overall ratio of condensing to total fuel.

Total FY 80 coal.

Product of total fuel (59) and ratio of condensing to total generation ((58) urrent cost of fuel ($28.26/ton) gives fuel cost of condensing generation.

Condensing generation fuel cost divided by the product of energy generated ndensing generation and ratio of generated energy to energy exported gives u of incremental (condensing generated) energy exported from plant.

Operating costs, other than fuel, associated with generation will not vary ficantly with incremental increases in electrical generation. Makeup (water not change since no condensate is lost in electrical generation. There may y small increase in supplies namely lubricants; however, this will be more t t by spreading maintenance costs equally over all electrical generation. It ed that no additional equipment (boilers or generators) will be operated to sh the energy covered by the Swap Act; therefore, the incremental cost will y recovered by using the average maintenance unit cost (62).

The total incremental unit cost is the incremental unit cost for fuel (61) p verage maintenance unit cost (62).

Contract DAKF70-81-S-0069

Exhibit "B"

Frame 7 G.E. Gas Turbines

Incremental Rate = Fuel Cost plus Maintenance Cost

Fuel Cost = Monthly Average Fuel Cost ($/gal) multiplied by .052 (gal/kwh)

Maintenance Cost = $.001 per kwh

Note: 1. .052 gal/kwh is the incremental heat rate.
2. Average fuel cost and BTU content will be determined monthly from purchaser's records.

EMD Diesel Units

Incremental Rate = Fuel Cost plus Lube Oil Cost plus Maintenance Cost

Fuel Cost = Monthly Average Fuel Cost ($/gal) multiplied by .084(gal/kwh)

Lube Oil Cost = $.002 per kwh

Maintenance Cost = $.004 per kwh

Note: 1. .084 gal/kwh is the incremental heat rate.
2. Average fuel cost and BTU content will be determined monthly from purchaser's records.

Frame 5 G.E. Gas Turbines

Incremental heat rate wasn't available at time of contract signing. To be determined prior to sale of replacement power for this unit.

ector of Facilities Engineering
d Infantry Brigade (Alaska)
t Richardson, AK 99505

CTOR CODE FACILITY CODE
ND ADDRESS

Golden Valley Electric Assoc. Inc
Box 1249
Fairbanks, Alaska 99707

8.

AMENDMENT OF SOLICITATION NO. ______

DATED ______ (See block

[X] MODIFICATION OF CONTRACT/ORDER NO. DAKF70-81

DATED ______ (See block

CK APPLIES ONLY TO AMENDMENTS OF SOLICITATIONS

above numbered solicitation is amended as set forth in block 12. The hour and date specified for receipt of Offers [ ] is extended, [ ] is not extended must acknowledge receipt of this amendment prior to the hour and date specified in the solicitation, or as amended, by one of the following methods: igning and returning ______ copies of this amendment; (b) By acknowledging receipt of this amendment on each copy of the offer submitted; or (c) By n which includes a reference to the solicitation and amendment numbers. FAILURE OF YOUR ACKNOWLEDGMENT TO BE RECEIVED AT THE ISSUING UR AND DATE SPECIFIED MAY RESULT IN REJECTION OF YOUR OFFER. If, by virtue of this amendment you desire to change an offer already submitted, e [illegible]gram or letter, provided such telegram or letter makes reference to the solicitation and this amendment, and is received prior to the opening hour a

INTING AND APPROPRIATION DATA (If required)

OCK APPLIES ONLY TO MODIFICATIONS OF CONTRACTS/ORDERS

This Change Order is issued pursuant to General Provisions 4, Change of Rates

The Changes set forth in block 12 are made to the above numbered contract/order.

The above numbered contract/order is modified to reflect the administrative changes (such as changes in paying office, appropriation data, etc.) set forth

This Supplemental Agreement is entered into pursuant to authority of ______

t modifies the above numbered contract as set forth in block 12.

PTION OF AMENDMENT/MODIFICATION

Under Special Provisions A(S), Item 4, Rates, delete $0.0418/KWH and insert in thereof $0.0509.

Add Exhibit A, Revision 1 and under Exhibit A, Computation of Costs and Charges delete Items 61, 62, 63, and 64.

ovided herein, all terms and conditions of the document referenced in block 8, as heretofore changed, remain unchanged and in full force and effect.

NTRACTOR/OFFEROR IS NOT REQUIRED SIGN THIS DOCUMENT [ ] CONTRACTOR/OFFEROR IS REQUIRED TO SIGN THIS DOCUMENT AND RETURN ______ COPIES TO IS

OF CONTRACTOR/OFFEROR

(Signature of person authorized to sign)

17. UNITED STATES OF AMERICA

BY ______ (Signature of Contracting Officer)

AND TITLE OF SIGNER (Type or print) | 16. DATE SIGNED | 18. NAME OF CONTRACTING OFFICER (Type or print) | 19

COMPUTATION OF COSTS AND CHARGES
STEAM AND ELECTRIC POWER PLANT
3596, FORT WAINWRIGHT, ALASKA

The following items shall supercede those items of the original Exhibit A.

| | | |
|---|---|---|
| 61. | Condensing Unit Fuel Cost<br>35/28.56 X .0375 | $0.0460/KWH |
| 62. | Maintenance Unit Cost<br>$228,350/67,950,400 KWH | $0.0034/KWH |
| 63. | Incremental Unit Cost | $0.0494/KWH |
| 64. | Rate (Incl 3% OH) | $0.0509/KWH |

Explanatory Notes For Items of Computation

61. The current (Jan 1, 1982) best estimate of coal cost is $35/ton; therefore 35/28.56 is the ratio of current to original coal cost. The original unit fuel cost was $0.0375/KWH.

62. This is the actual maintenance cost for FY1981 adjusted for a 6.4% increase in wage rates divided by FY1981 production.

EXHIBIT A, REVISION 1
CONTRACT DAKF70-81-S-0069 21 Jan 82

*wright Power Plant, opposite p help conserve expensive fuel c ER: GVEA Manager Robert and Senator Ted Stevens, rig with Congressman Don Yo representatives from the Go office, state and federal ener cies, the Department of Defe Usibelli Coal, all helped b Swap Act to reality.*

/hen Hufman first began working GVEA in 1953, the utility company s operating out of an old carpenter's p owned by Fairbanks Exploration npany. Since then he has watched EA expand as Fairbanks energy ds have grown. Escalating oil pri- world-wide oil supply shortages, l the nation's energy policy have all ouraged the use of coal in place of Coal-fired energy is more attractive l economical for Fairbanks when consider the proximity of the Usi- i Coal Mine. And it's wasteful not to ke use of coal-fired energy that is ilable on a daily basis from the e facilities.

uring the Arab oil embargo of 1973- GVEA was temporarily allowed to power from Ft. Wainwright's it. At that time GVEA was short on erating capacity as they were expe- cing a severe oil supply shortage. Don Young was instrumental in iring the first contract during the argo. He worked closely with ies Schlesinger, Secretary of De- ie," Hufman said.

owever, once the embargo was lift- nd the emergency over, the Depart- it of Defense refused to sell any e electricity to GVEA. This may e partially been due to Schlesinger ing office.

ufman began writing a series of let- to the Department of Defense, artment of Energy and later to the ident, requesting that there be an nsion of the contract in order to serve oil. For the past seven years man has received rejection letters r all levels of the federal govern- t.

eputy Assistant Secretary of De- isting, the Army had no authority under the present law to sell excess power from Ft. Wainwright to GVEA. Should GVEA consider the benefits from a coal-fired plant to be more eco- nomically attractive, you of course have the option to build such a plant and thereby reduce your current oil consumption."

Although the Department of Energy was sympathetic to GVEA's requests, they had no jurisdiction over the De- partment of Defense. Even though President Carter's administration had sought to reduce our dependence on oil by utilizing coal, Hufman received no help from the executive branch. He came to the conclusion that there was no effective energy conservation policy.

Hufman refused to give up. He con- tinued to seek support for reducing GVEA's dependence on oil and thereby controlling the rapidly rising costs to local consumers. The base command- ers at Wainwright and Eielson Air Force Base cooperated and made re- commendations to the Pentagon and the Department of Energy in support of selling their surplus energy. The an- swer from Washington D.C. was still *no*.

Finally Hufman realized that it would take an Act of Congress for GVEA to save millions of gallons of oil each year. He approached Young and Stevens for assistance. They worked closely together in the fall of 1979 to introduce legislation that would grant military facilities an authority to sell their excess energy to utility compan- ies.

GVEA also placed a large ad in the *Washington Post* showing a copy of letter and the editorial cri Administration for its energ vation policy. Hufman hoped lic pressure would draw mor for the Swap bill. He receiv personal letters in response t most people being "outrag GVEA was having so muc getting action from Washing

In March of 1980 Hufman te the House Sub-committee or Development hearings, suppo Swap bill. He spoke of the sa annual energy costs based o oil prices. He emphasized tha ing structure guaranteed a pr federal government, and that of the excess energy would military plants to run at a mu efficiency, thereby reducing t all cost of production."

Whether an everyday con boomer or an environmentali body wins with the Swap bil prising that such a simple, method for conserving our p resources could take GVEA work and finally an Act of Co make legal.

"I've been fighting for this years," Hufman said in frus

It is not as though Fairba desperate need of this surpl that the bases are capable o ing. GVEA receives 60 perc energy from the Healy coal-fi which runs wide-open most o The other 40 percent of it comes from oil-fired turbines at headquarters, the North F facility, and at the Univ Alaska.

But why continue to burn you can buy cheaper excess energy next door?

Thanks to years of contin on the part of Hufman and cently our legislators, we now Alaska Federal-Civilian En ciency Swap Act. Millions of oil will be saved, and this w all of GVEA's customers. Mo tantly, the Swap Act allows t government and utility com

# Appendix B: Technologies Background Information

The following technologies are evaluated in this appendix:



## Nuclear Power

Concern about global greenhouse warming is leading to reconsideration of the nuclear power option. Many of the world's nations, both industrialized and developing, believe that a greater use of nuclear energy will be required if energy security is to be achieved.

Two issues—the risk of reactor accidents and high cost—must be dealt with effectively to have a resurgent nuclear industry. A third issue—the nuclear power weapons connection—must also be addressed.

Although large-size reactors of 1,000 megawatts (MW) and larger get most of the research and development (R&D) attention, small reactors are being considered as well (Table B1).

Table B1. Small reactors under development.

| Reactor | Description | Owner |
|---|---|---|
| CAREM | 27 MWe PWR | CNEA & INVAP, Argentina |
| KLT-40 | 35 MWe PWR | OKBM, Russia |
| MRX | 30-100 MWe PWR | JAERI, Japan |
| IRIS | 50 MWe PWR | Westinghouse, USA |
| Modular SBWR | 50 MWe BWR | GE & Purdue University, USA |

Small reactors are most applicable for smaller loads that are remote and isolated from interconnection to a larger grid. However, smaller units could also be installed on a modular basis for use on large power grids. The cost of electricity from a 50-megawatt-electric (Mwe) unit is estimated by the U.S. Department of Energy (DOE) as 5.4 to 10.7 cents/kilowatt-hour (c/kWh). However, this has yet to be demonstrated.

The U.S. Congress is funding research on both small modular nuclear power plants (assembled onsite from factory-produced modules) and advanced gas-cooled designs (which are modular in the sense that up to ten or more units are progressively built to constitute a major power station). A DOE report in 2001 considered nine designs that could possibly be deployed by 2010.

Four small nuclear reactors are operating in a remote corner of Siberia at the Bilibino Cogeneration Plant. These four 62-megawatts thermal (MWt) units are an unusual graphite-moderated boiling water reactor (BWR) design with water/steam channels through the moderator. They produce steam for district heating and 11 MWe (net) electricity each. They have performed well since 1976, much more cheaply than fossil fuel alternatives in the Arctic region.

The CAREM (advanced small nuclear power plant) being developed by CNEA and INVAP in Argentina is a modular 100-MWt/27-MWe pressurized water reactor with integral steam generators designed to be used for electricity generation (27 MWe or up to 100 MWt), as a research reactor, or for water desalination. CAREM has its entire primary coolant system within the reactor pressure vessel, self-pressurized and relying entirely on convection. Fuel is standard 3.4 percent enriched pressurized water reactor (PWR) fuel with burnable poison, and the reactor is refueled annually. It is a mature design that could be deployed within a decade.

The International Reactor Innovative & Secure (IRIS) is being developed by Westinghouse as a Generation IV project (Table 65).* IRIS-50 is a modular 50-MWe or more PWR with integral primary coolant system and circulation by convection. Fuel is similar to present light water reactors (LWRs). Enrichment is 5 percent, with burnable poison and a fueling interval of 5 years (or longer with higher enrichment). IRIS-50 could be deployed this decade.

* Generation IV is the DOE's Office of Nuclear Energy, Science and Technology designation for the next generation of nuclear energy technology.

The Modular Simplified Boiling Water Reactor (MSBWR) is being developed in the United States by General Electric and Purdue University at both 200-MWe and 50-MWe levels based on GE's SBWR. This reactor (Figure B1) uses convection in the coolant and has 5 percent enriched BWR fuel with a 10-year refueling interval. It may be ready for deployment this decade.

Table B2. Generation IV project acronym list.

| Generation IV System | Acronym |
|---|---|
| Gas-Cooled Fast Reactor System | GFR |
| Lead-Cooled Fast Reactor System | LFR |
| Molten Salt Reactor System | MSR |
| Sodium-Cooled Fast Reactor System | SFR |
| Supercritical-Water-Cooled Reactor System | SCWR |
| Very-High-Temperature Reactor System | VHTR |

The Generation IV nuclear energy systems, which have so far received most of the R&D attention and funding, include technologies ranging from 100 MW to 2,000 MW, all too large for the Fairbanks area.

## Using Nuclear Power in Alaska

### Public Perception

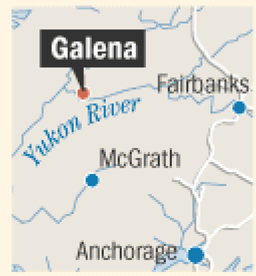
New nuclear reactor being offered to Alaska village. A Japanese corporation recently approached the Interior Alaska community of Galena regarding donating a new, unconventional electricity-generating plant that would light and heat the Yukon River village pollution-free for 30 years using a nuclear reactor.

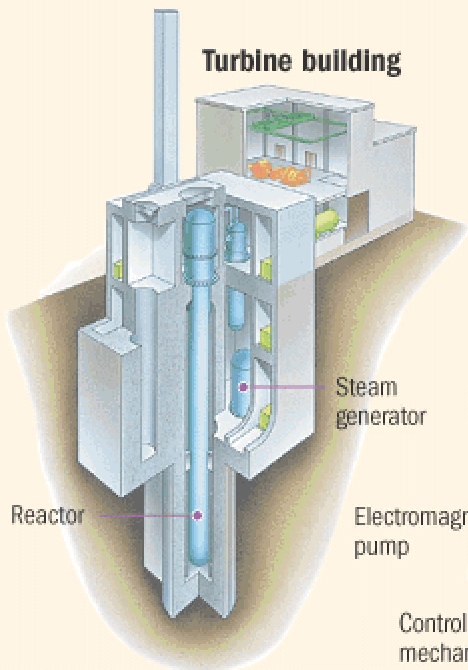
Per DOE officials, the new technology is promising, but enormous hurdles remain. A reactor of this type and size has never been built anywhere in the world, much less tested and licensed for use in the United States. In addition, the cost of building a prototype that meets stringent U.S. safety standards could "kill it" altogether.

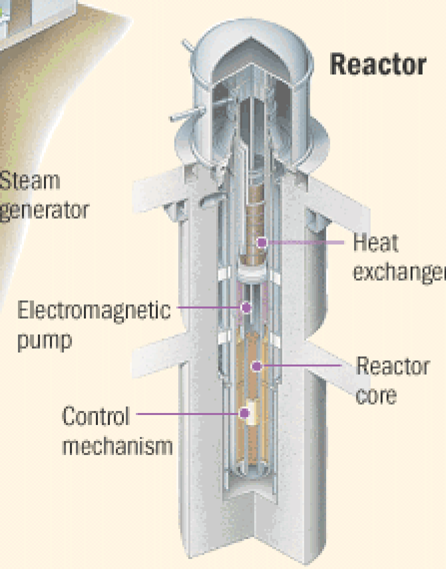
Public skepticism is another potential barrier. The proposed plant would be the first commercial use of nuclear power in Alaska, and fears about potential accidents and about disposal of nuclear waste have chilled the local industry in the Lower 48. No new commercial plants have been licensed since the late 1980s.

# Nuclear power for rural villages

Toshiba is proposing a small modular nuclear reactor to supply power for Galena, a Yukon River town of 713. It has yet to be constructed, but would likely consist of a 70-foot tube with a garbage-can-sized uranium core at the bottom and a liquid metal heat exchanger in the upper section. The assembly would be buried in a concrete silo. The slow-burning uranium would last 30 years, powering steam turbines to create electricity. Conceptual drawings of the plant are below.




## Reactor specs

- **HEIGHT:** About 70 feet
- **WEIGHT:** About 60 tons
- **ELECTRICAL PRODUCTION:** About 10 megawatts. A typical Lower 48 nuclear plant is 1,000 megawatts or more. When the fuel is spent, the core can be removed and recycled.
- **ELECTRICAL COST:** The plant could generate electricity at 10 cents a kilowatt hour, which is slightly more than in Anchorage or Fairbanks, but a half to two-thirds the current cost in Galena.
- **CONSTRUCTION:** The modular plant is constructed in a factory and could be delivered by barge to the site. Components are small enough to be delivered by truck or helicopter.
- **PROJECT COST:** $20 million. Toshiba says it will install the Galena reactor free, as a demonstration project.
- **NUMBER OF EMPLOYEES:** The reactor has no operator or maintenance personnel; the steam generator would probably require the same number of people as the diesel-powered plants.

Source: Toshiba

RON ENGSTROM / Anchorage Daily News

Figure B1. Modular simplified boiling water reactor.

The reactor core would be constructed and sealed at a factory, then shipped to the site. There it would be connected with the other nonnuclear parts of the power plant to form a steel tube about 70 ft long with the nuclear core welded into the bottom like the eraser in a pencil. The assembly is then lowered into a concrete housing buried in the ground, making it as immune to attack or theft as a missile in its silo.

The reactor has almost no moving parts and does not need an operator. The nuclear reaction is controlled by a reflector that slowly slides over the uranium core and keeps the nuclear fission (see technology description above) critical. If the reflector stops moving, the reactor loses power. If the shield moves too fast, the core "burns" more quickly, yielding the same amount of power, but reducing the reactor's life. Because of its design and small size, the Toshiba reactor is not expected to overheat or melt down, unlike what happened in the 1986 accident at Chernobyl that killed 30 people and released radiation across northern Europe.

The nuclear reaction heats liquid sodium in the upper portion of the reactor assembly. It circulates by convection, eliminating pumps and valves that need maintenance and can cause problems. The liquid is contained in a separate chamber, so it is not radioactive. Because the reactor assembly is enclosed in a thick steel tube, it is expected to withstand earthquakes and floods.

*Supporters, including U.S. Senator Ted Stevens, acknowledge it will be difficult to persuade Alaskans to embrace nuclear power in Galena or elsewhere. But even environmental groups say the incentive to replace expensive diesel fuel as the source of electricity in rural Alaska is reason to continue investigating small reactor technology.*

*The Galena design is part of a new generation of small nuclear reactors that can be built in a factory and transported by barge, truck, or helicopter. A Federal study funded at Senator Stevens' request and published in May 2001, found they are inherently safe and easy to operate, resistant to sabotage or theft, cost-effective, and transportable.*

*Toshiba Corporation, the Japanese electronics giant, calls its reactor the 4S system: super-safe, small, and simple.*

Per Hermann Grunder, director of Argonne National Laboratory in Chicago, a Federal research facility that has investigated the new generation of reactors, the Toshiba design looks safe on paper. Liquid sodium eliminates corrosion, which is a primary cause of nuclear power plant accidents. "The probability of radioactive material leakage for this system would be extremely low," Grunder wrote to the newspaper, *Anchorage Daily News*.

At this time, the biggest hurdle this

reactor faces is winning approval by the U.S. Nuclear Regulatory Commission, he said, which will require Toshiba to finish its design, then build a prototype. The work is estimated to cost $600 million or more and to take 6 to 8 years to complete. Toshiba will need financial aid from the U.S. and Japanese governments to develop its 4S technology.

Federal licensing alone may not be enough for Galena to go nuclear, even if it receives public acceptance. The U.S. Air Force had to remove ten small generators powered by a radioactive source in the northeastern Interior in 2001 after the nearest villagers learned about the material and complained.

Nuclear watchdog and environmental groups said they know little about Toshiba's small reactor. Toshiba's claim that its reactor will run trouble-free for 30 years is very positive, but projections for the technology remain to be proven.

### Benefits

- Nuclear energy is emission free.
- Nuclear energy could reduce America's demand for foreign oil by nearly 300 million barrels a year, reducing our dependence on foreign oil suppliers.
- Nuclear energy saves fossil fuel resources. Nuclear power generation has already saved the United States a total of 4.1 billion tons of coal between 1973 and 1999.

### Disadvantages

- Nuclear power plants may potentially cause extreme long-term environmental hazards (should things go wrong). Recent such experiences include Chernobyl and Three Mile Island. For these reasons, there are no new orders for nuclear power reactors in the United States, and some operating power reactors are being permanently shut down.
- Nuclear power plants are very costly and very difficult to permit. Because of this, they have historically been large plants of 500 MW or more.
- Public perception of nuclear energy is predominantly negative and will not change soon unless a substantially new technology is proven.
- Disposal of radioactive waste is a very hazardous and costly procedure that follows the shutdown of the nuclear plant.
- Small-size reactors are hardly available.

### Conclusion

At this time, we do not recommend a nuclear energy alternative for the Fairbanks area. No small nuclear reactors of 60 MW or less have received U.S. Nuclear Regulatory Commission approval yet.

Although many small-scale applications are under development, there are significant and regulatory hurdles to overcome. Development efforts must demonstrate failsafe operating characteristics to have any hope of overcoming the predominantly negative public perception of nuclear power.

Small-scale nuclear power will not be considered further. At some point in the future, it may offer a significant alternative to fossil fuels.

## Solar Power

## Technology Description

Solar electric panels are composed mainly of silicon. Silicon is used to generate electricity because it naturally releases electrons (electrical energy) when hit with a photon (light source).

Most solar panels consist of a clear protective top layer, two layers of specially treated silicon with collecting circuitry attached to the top layer, and a tough polymer backing layer. From there, the panel can be framed (adds durability) or unframed (reduces weight), and in some cases the layers are even comprised of flexible materials. The vast majority of PV panels work as follows:

The top layer of silicon is treated to give it an electrically negative character. The back layer is treated to make it electrically positive. Due to these treatments and added elements, the top layer is rich in electrons, and the back layer is relatively electron poor. These two layers are separated by an electrically charged junction, which allows electrons to flow from back to front, but not the other way around.

When light strikes the PV panel, the silicon layers absorb some of the photons. The photons cause electrons to be released from the silicon crystal, and those electrons “wander around” looking for somewhere to attach themselves. Some of the electrons are freed from the bottom layer, and they find their way through the junction into the top (electron rich) layer. Some of the electrons are freed from the top layer, and since they cannot travel to the bottom (electron poor) layer, and are being “crowded” by new

electrons from the bottom layer, they are left free to be collected by electrical contacts on the surface of the top layer.

Those collected electrons are routed through an external circuit, providing power to the electrical system attached to the panels. The circuit is completed when the electrons return to the bottom layer of the PV panel, find “resting spots” in the electron poor bottom layer, and wait for the next photon to shake them loose.

There are no moving parts in the PV panel, so maintenance is limited to keeping the junction boxes and wiring free from moisture and corrosion, and keeping the surface of the panel clean enough to allow light through to the silicon layers.

Most PV systems need a battery to store electricity to provide power when the sun is not shining, or when electricity demand exceeds the power output of the solar panel(s). Thus, the power is drawn out of the stored battery power, and the solar panels recharge the batteries when their charge drops below a certain level.

Solar electric panels are probably one of the simplest alternative energy sources to use. They can be mounted on a rooftop or a freestanding solar array rack.

### Technology Characteristics

PV cells are wired together in modules, or panels, with a specific power output required to meet the power demands. There are various types of cell technologies. The most widely used PV cells are:

- single-crystal silicon
- multi-crystal silicon
- amorphous silicon.

Single-crystalline cells are the most efficient at converting sunlight to electricity. Multi-crystalline cells are slightly less efficient than single-crystalline. Advanced amorphous silicon cells are about half as efficient as single-crystalline cells.

Modules are specified on a peak-Watt (Wp) basis at standard test conditions (STC = 1,000 Watts/square meter solar radiation at 1.5 atmospheres

and 25 °C ambient temperature). A *module's Wp rating* is approximately the amount of power it will generate at solar noon on a clear day.

Modules produce the rated output at a specified voltage and current (or amperage). Modules are available in capacities ranging from a few Wp to as high as several hundred Wp. The higher the Wp rating, the larger the size of the module. Single-crystalline cell based modules are about one square foot in area for every 10 Wp capacity. Modules can be wired together in arrays to meet any power requirement.

The optimal type of PV battery is a deep-cycle (or deep discharge) battery that can be repeatedly drained of much of its energy and recharged. A variety of battery technologies are available, but lead-acid is the most common. Batteries are sized based on their Amp-hour capacity (number of amperes supplied over time) and their charge/discharge rate.

Other system components include junction and distribution boxes, wiring, fuses, circuit breakers, safety disconnects, lightning protection, and a grounding circuit to protect the system components as well as anyone using the system. These components are common to any electrical system.

### Natural Resource

For optimum system performance, photovoltaic modules should have full exposure to the sun from at least 10 am to 3 pm all year round. In Alaska, where solar availability in winter season is negligible, PV cannot be expected to provide power year round, and, therefore, can not be a reliable source of the firm power required for the Fairbanks area.

### Technology Maturity

The solar technology has made great advances during past decade. Many solar panel types are currently available on the market, and appear to be technologically suitable for Alaska applications.

Flexible panels are limited to smaller output sizes. They tend to be more expensive per watt of rated output, and less durable in long-term applications.

Unframed rigid panels also tend to be available primarily in smaller sizes. They're much lighter weight than the more common framed panels, and convenient for portable applications. What these panels lose in conveni-

ence as compared to flexible panels, they make up in cost per watt and durability.

Framed rigid panels are the most common type of solar panel for full solar power systems. They are the most durable type of panel, and are generally used in permanent or long-term installations for household, RV or marine power systems.

Solar roofing is one of the newer styles of photovoltaic unit. For a large household system, solar roofing can be found that mimics the appearance of regular roofing shingles or regular metal channel roofing. Probably the most cosmetically pleasing option for a full-house solar system, these products are now becoming available on a widespread basis.

### Life Expectancy and Life Cycle Cost

The operating life of the PV modules and other system components is an important factor when considering a PV system. Many module manufacturers now provide performance warranties of twenty years or longer. Operating lives of other components, especially batteries and inverters shall also be considered, especially as batteries and inverters are generally replaced before modules. Although PV modules are usually the largest part of the initial system purchase cost, the battery may be the largest part of a system's life-cycle cost.

### Technology Applications

Hundreds of homes in Alaska now use solar electric (photovoltaic or PV) systems to provide their electricity for most of the year. With proper sizing, installation, and maintenance, a PV system can provide a *seasonal power* for an Alaskan home.

### Size

The number of modules and the size of the battery bank, wires, controller, fuses, inverter, etc. mainly depends on the amount of power needed, and the amount of solar radiation available at given location on a daily and seasonal basis. System sizing is usually based on the maximum energy demand during the month of lowest solar radiation intensity.

A one kilowatt-peak capacity PV array (with single-crystalline modules), at around 100 sq ft will produce about 1 kilowatt (1,000 Watts) at solar noon

on a clear sunny day. If the system was located in Fairbanks, on average, it will produce about 3.3 kWh of direct current electricity per day throughout the year (more in the summer and less in the winter).

The lack of sunshine in the wintertime makes solar an impractical firm power resource for the interior of Alaska.

### Utility-Connected Systems

Some PV systems can be connected to an electric utility's power transmission and distribution system (power grid). The system owners sell their excess electricity to the utility company, and buy electricity when their PV system cannot meet their electricity demand. In effect, they use the utility grid for PV power storage. Inverters are available that produce electricity of the quality acceptable to electric utilities. They incorporate safety features to automatically disconnect the PV system from the grid in case of a power outage on the grid.

With current high prices for modules (and inverters), and low solar availability in Alaska, it is difficult to justify a utility-integrated system on the basis of electricity sales to the utility alone.

### System Costs and Considerations

It is generally difficult to predict the cost of a PV system because of the site and owner- specific variables involved in system sizing and installation. PV module purchase prices are currently about $5-$7/Wp. Depending on the size and quality of the system, other component prices and installation costs may add $5-$11/Wp for a total DC system cost of $10-$18/Wp.

The initial cost of PV systems remains one of the major impediments to its widespread use.

### Potential Installation in Interior Alaska

Although solar panels can be practical in Alaska in summer and PV panels do operate more efficiently in colder temperatures, PV panels are of little use November through January. There simply are not enough hours of daylight to produce much power (and continuous clearing off snow off the panels is necessary to make the most of those few hours of light). As a result, an alternate power source is a must during these months.

There are hundreds of remote Alaskan homes that use PV for summer season electricity. For commercial and industrial use, PV panels can be put to use in Alaska to power monitoring stations, signal lights, telecommunications towers, and other remote sites where there are no full-time employees stationed. Solar power is also useful for small power loads even in grid-powered areas where running grid power to the load would be inconvenient or expensive (such as signal lights on an airstrip or parking lot lighting). However, the power output varies and can not be reliable, especially during winter season.

### Benefits

Photovoltaic power is one of the most benign forms of electrical power available today. It produces no emissions, uses no fuel, and other than the power storage batteries, PV system components are all solid-state, with no hazardous materials involved.

Photovoltaic power is one of the simplest alternative energy sources to use. The solar electric panels can be mounted on a rooftop or a freestanding solar array rack.

Most rigid photovoltaic panels come with 20-25 year warranties on their rated power output.

There are no moving parts in the PV panel, and they require virtually no maintenance during the warranty period, except for cleaning the surface of the panels and maintaining a proper fluid level in the storage batteries.

### Disadvantages

The solar resource is significantly limited during the winter season, and, therefore, solar power output varies and can not be consistently relied upon. Solar power in Alaska can only be a seasonal power source.

Although initial cost of the PV modules has come down considerably, its payback on investment remains high.

Based on the above PV module size requirements (100 sq. ft per 1 kW of peak electricity), the overall PV area requirements for even partial load will be too large to be installed. For example, 20 MW of peak power will require a 2 million sq ft (~46 acres), of PV panels. Still, even such enormous PV area can only guarantee the above peak power production at noon-

time on a clear sunny day. In addition, in wintertime, even during the limited solar time, a clearing of snow off the PV panel will be required almost continuously. Solar power here cannot be considered firm power source in the Fairbanks area.

### Conclusion

Solar power in Alaska can not be considered a firm power, and, therefore, is not considered further.

## Wind Power

### Technology Description

*Wind Turbine Types*

The basic wind energy conversion device is the wind turbine. Although various designs and configurations exist, these turbines are generally grouped into two types:

1. *Vertical-axis wind turbines*, in which the axis of rotation is vertical with respect to the ground (and roughly perpendicular to the wind stream),
2. *Horizontal-axis turbines*, in which the axis of rotation is horizontal with respect to the ground (and roughly parallel to the wind stream.)

*Wind Power Density* is a useful way to evaluate the wind resource available at a potential site. The wind power density, measured in watts per square meter, indicates how much energy is available at the site for conversion by a wind turbine. *Classes of wind power density* for two standard wind measurement heights are listed in the reference table under the "Natural Resource" section. Wind speed generally increases with height above ground.

*Wind Generator Applications*

The primary consideration in a wind generator is the average wind speed at the installation site.

Different turbine designs are used to provide optimum performance at sites with different average wind speed. Generally, low speed generators will either have longer rotor blades or a larger number of short, wide blades to maximize power drawn from minimal wind. High-speed generators may be built of more durable material, and will have narrow, relative-

ly short blades to minimize potential rotor damage in extremely high winds.

Before choosing which type of turbine is best for a particular site, wind speed measurements need to be taken for a few consecutive months (or ideally, a full year). With long-term wind measurements, an accurate average wind speed can be calculated, and the expected maximum wind speeds known. Armed with this information, a turbine can be chosen that will maximize performance at the average wind speed, as well as one that will withstand the likely maximum forces.

### Natural Resource

Wind resource evaluation is a critical element in projecting turbine performance at a given site. The energy available in a wind stream is proportional to the cube of its speed, which means that doubling the wind speed increases the available energy by a factor of eight. Furthermore, the wind resource itself is seldom a steady, consistent flow. It varies with the time of day, season, height above ground, and type of terrain. Proper siting in windy locations, away from large obstructions, enhances a wind turbine's performance.

Fairbanks area is not considered a good location for wind power because of light winds (see Figure B2, wind chart and wind power class data), and many calm times. The Big Delta area, south of Fairbanks, is more attractive and is being considered by GVEA for wind power.

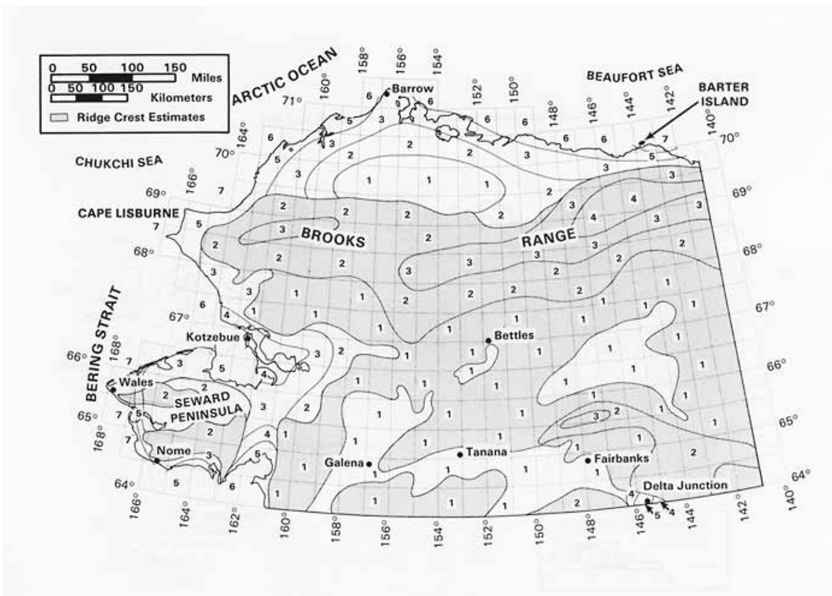
### Technology Maturity

Wind energy is the fastest-growing energy technology in the world. Pressure to develop new technology is being fueled by exploding world wind energy markets that already top $1.5 billion a year. The American Wind Energy Association predicts this figure will grow as much as tenfold during the next decade.

The U.S. Department of Energy has been working with the wind industry since 1992 to rapidly develop innovative, low-cost wind technologies to compete in global energy markets. The first turbines created under these partnerships are already on the market, and a whole new generation of turbines should arrive soon.

## Technology Applications

In 2001 the international wind power industry installed more than 6,500 megawatts (MW) of new wind energy generating capacity, bringing total installed capacity to about 24,000 MW. In the United States alone, close to 1,700 new megawatts came on line in 2001. Wind farms across the country are currently generating about 10 billion kilowatt-hours (kWh) annually, enough to power one million average American homes. As customer demand for clean energy grows and the costs associated with wind power continue to drop, utilities are expected to increase their use of this clean, reliable energy resource.




| Classes of Wind Power Density at 10 m and 50 m[a] | | | | |
|---|---|---|---|---|
| | 10 m (33 ft) | | 50 m (164 ft) | |
| Wind Power Class | Wind Power Density (W/m$^2$) | Speed[b] m/s (mph) | Wind Power Density (W/m$^2$) | Speed[b] m/s (mph) |
| 1 | <100 | <4.4 (9.8) | <200 | <5.6 (12.5) |
| 2 | 100 - 150 | 4.4 (9.8)/5.1 (11.5) | 200 - 300 | 5.6 (12.5)/6.4 (14.3) |
| 3 | 150 - 200 | 5.1 (11.5)/5.6 (12.5) | 300 - 400 | 6.4 (14.3)/7.0 (15.7) |
| 4 | 200 - 250 | 5.6 (12.5)/6.0 (13.4) | 400 - 500 | 7.0 (15.7)/7.5 (16.8) |
| 5 | 250 - 300 | 6.0 (13.4)/6.4 (14.3) | 500 - 600 | 7.5 (16.8)/8.0 (17.9) |
| 6 | 300 - 400 | 6.4 (14.3)/7.0 (15.7) | 600 - 800 | 8.0 (17.9)/8.8 (19.7) |
| 7 | >400 | >7.0 (15.7) | >800 | >8.8 (19.7) |

Figure B2. Wind chart and wind power data.

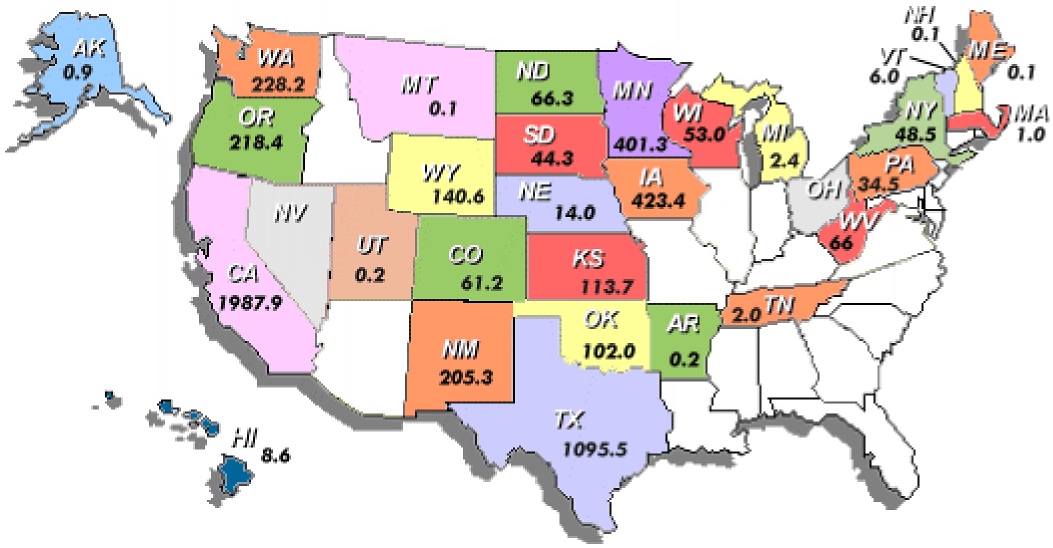



Figure B3. Total installed U.S. wind energy capacity: 5,325.7 MW as of 27 October 2003.a

Tables B3 and B4 show information about both existing wind energy sites in Alaska and new wind projects. As of today, Alaska has installed three times the wind power capacity it originally planned to be installed.

Use Tables B3 and B4 below to interpret the wind data shown on the wind chart above. The Wind Power Class in the Fairbanks Ranch is "1," which corresponds with the lowest wind power density of <100 w/sq. meter. In general, sites with a Wind Power Class rating of 4 or higher are now preferred for large scale wind plants.

Table B3. Alaska state summary.

| Total MW = 0.925* Planned MW = 0.3* | | | | | |
|---|---|---|---|---|---|
| Alaska Wind Energy Development | | | | | |
| Existing Project or Area | Owner | Date Online | MW | Power Purchaser/ User | Turbine/ Units |
| 1. Kotzebue | Kotzebue Electric Assoc. (KEA) | 1997 | 0.15 | Kotzebue Electric Assoc. | Atlantic Orient (3) |
| St. Paul Island | Tanadgusix Corp. | March 1999 | 0.225 | Tanadgusix Corp. | Vestas (1) |
| 1. Kotzebue (Phases II and III) | Kotzebue Electric Assoc. | May 1999 | 0.35 | Kotzebue Electric Assoc. | Atlantic Orient 15/50 (7) |
| Wales Wind Energy Project | Kotzebue Electric Assoc. | Oct 2000 | 0.1 | Alaska Village Electric Coop | Atlantic Orient 15/50 (2) |
| 1. Kotzebue | Kotzebue Elec. Assoc. | 2002 | 0.1 | Kotzebue Elec. Assoc. | NPS Northwind 100 - |

Table B4. New Alaska wind projects.

| Utility/Developer (Project) | Location | Status | MW Capacity | On Line By/ Turbines |
|---|---|---|---|---|
| KEA/ Alaska Village Electric Coop (Kotzebue Wind Project) | Kotzebue | Under Construction | 0.1 | 2003 / AOC 15/50 |
| Selawik Wind Project | Selawik | Under Development | 0.2 | 2003 / AOC 15/50 |

### Size

A single wind turbine size varies from 1 kW to several MW units. Most wind farms are using 0.6 to 1.5 MW turbines.

### Utility-Connected Systems

In general, annual average wind speeds of 5 meters per second (11 miles per hour) are required for grid-connected applications. Annual average wind speeds of 3 to 4 m/s (7-9 mph) may be adequate for non-connected electrical and mechanical applications such as battery charging and water pumping. Wind resources exceeding this speed are available in many parts of the world.

### Potential Installation in Interior Alaska

With the right site, a steady wind flow is possible all year. Moreover, most sites will have more wind during the winter months.

As discussed above, the Big Delta area is a potentially attractive area for wind power development and is currently being considered by GVEA for wind power, as is the Healy area.

Because the capacity factor for a good wind site is typically about 35 percent, wind power is not reliable as a source of primary power. It is an excellent source of energy that can displace the use of fossil fuels.

### Benefits

- Like solar power, a wind energy system is an entirely clean source of power. The only potentially hazardous materials involved are the storage batteries.

- Wind turbines use no traditional fuel, and its energy cost is low.
- Wind can provide reliable year-round power given *the right location*.
- Wind generators require relatively little maintenance.

#### Disadvantages

- At lower wind speeds, the power output drops off sharply. This can be explained by the cubic power law, which states that the power available in the wind increases eight times for every doubling of wind speed (and decreases eight times for every halving of the wind speed).
- One possible problem with wind turbines is the remote possibility of the propeller icing up in winter, which, if happens, will impact wind turbine operation. However, if the wind generator is mounted in a clear location (without snow blowing off surrounding surfaces into the turbine) with fairly steady winter winds, the constant motion of the turbine should be sufficient to keep the propeller clear.
- Light winds in Fairbanks and many calm times do not make wind power a reliable primary source of power.

#### Conclusion

Although wind can be an attractive addition to a mix of power resources, it is not a viable firm power source (light winds and many calm periods). Wind power is not considered further in the evaluation of alternatives.

GVEA's wind power development efforts provide an excellent opportunity for the military to participate in renewable resource development and utilization in the interior of Alaska.

### Municipal Solid Waste to Energy

#### Technology Description

MSW—more commonly known as trash or garbage—consists of everyday items such as product packaging, grass clippings, furniture, clothing, bottles, food scraps, newspapers, appliances, paint, and batteries (Figure B4).

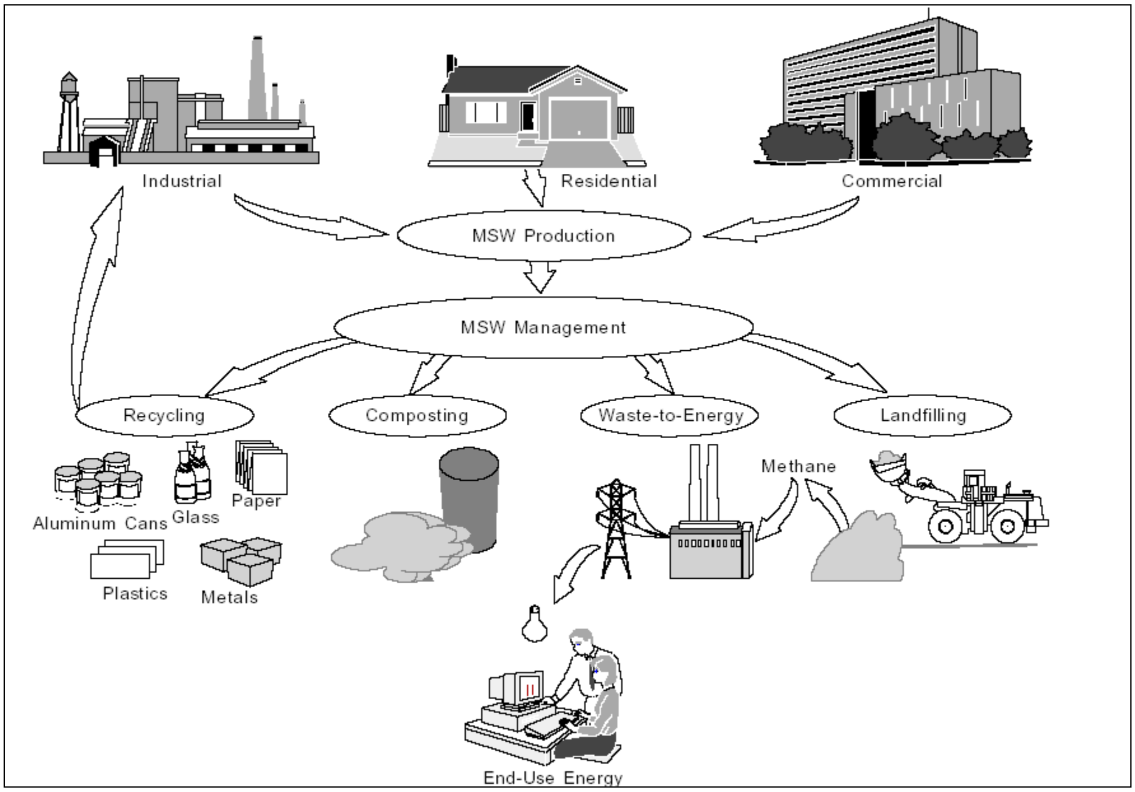



Figure B4. Sources of municipal solid waste (MSW).

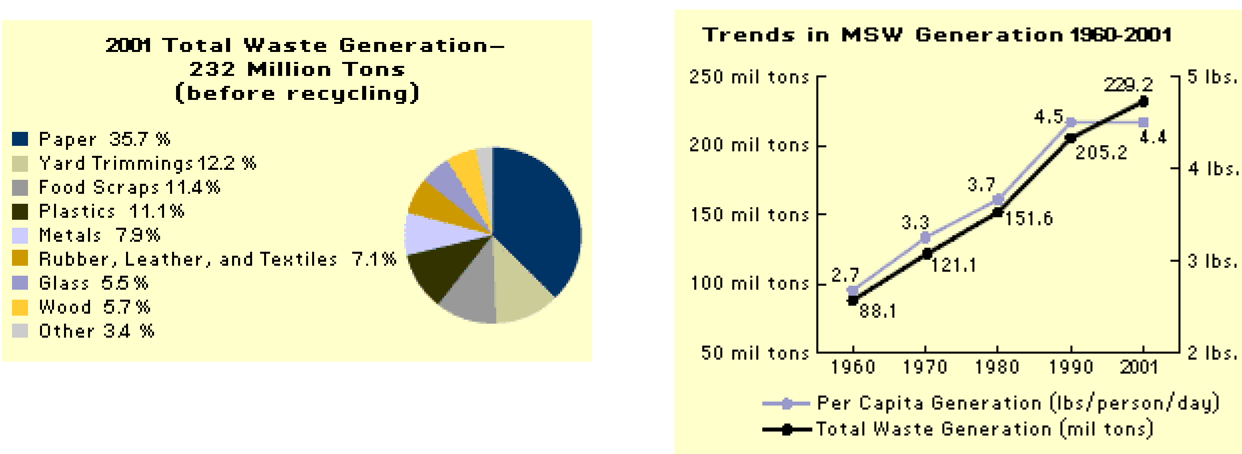



Figure B5. Growth of MSW generation.

MSW generation has grown considerably during past 40 years (Figure B5), and its disposal methods have evolved accordingly.

Several MSW management practices, such as source *reduction*, *recycling*, and *composting*, prevent or divert materials from the waste stream. Other practices address those materials that require disposal.

Worldwide, the dominant methods of MSW disposal are to place it into landfills or on open rubbish tips. Although these disposal methods have low initial costs, they may contribute to air and water pollution; they produce obnoxious odors; they look unsightly; and they release methane which is an explosive gas with a high global warming potential.

Open-air combustion also has environmental problems. Even incineration under controlled conditions is frequently opposed due to possible toxic emissions and the poor or zero energy recovery from the wasted resource.

Waste-to-energy projects can alleviate disposal problems, and can partly offset the costs of disposal. Because heat and power generation is the subject of this study, this review discusses the solid waste-to-energy technologies.

There are three ways to convert MSW to energy:

1. Direct combustion in waste-to-energy facilities with minimal processing, known as mass burn.
2. Direct combustion after moderate to extensive processing, referred to as refuse-derived fuel (RDF).
3. Gasified using pyrolysis or thermal gasification techniques and the gas used as a fuel.

*Direct Combustion and Incineration (Mass Burn)*

Mass burn technology involves the combustion of unprocessed or minimally processed refuse. The major components of a mass burn facility include:

- refuse receiving, handling and storage systems
- the combustion and steam generation system (a boiler)
- a flue gas cleaning system
- the power generation equipment (steam turbine and generator)
- a condenser cooling water system
- a residue hauling and storage system.

On a larger scale applications, solid waste (including agricultural and forestry residues), can be combusted in furnaces to produce process heat to feed steam turbine generators (see picture above), sized between 25 and 75 MW.

*Refuse-Derived Fuel*

Using raw, unprocessed MSW as a fuel is problematic because of the variable nature of the material from area to area and seasonally. It also has a low heat value and high ash and moisture content. This makes it difficult for to always provide acceptable pollution free levels of combustion. Processing of the waste to RDF partially overcomes these problems and the fuel can then be used more successfully.

Refuse-derived fuel (RDF) typically consists of pelletized or "fluff" MSW that is the by-product of a resource recovery operation. More involved processing can remove iron materials, glass, grit, and other non-combustible materials.

Using processed waste (where recyclable and non-combustible components have been removed), for power generation dramatically increases the efficiency of the waste-to-energy process, but at an increased cost due for material handling.

Both the RDF processing facility and the RDF combustion facility are usually located near each other, if not on the same site.

*Pyrolysis/Thermal Gasification*

In principle, gasification is the thermal decomposition of organic matter in an oxygen deficient atmosphere producing a gas composition containing combustible gases, liquids and tars, charcoal, and air, or inert fluidizing gases. Typically, the term "gasification" refers to the production of gaseous components, whereas pyrolysis, or pyrolization, is used to describe the production of liquid residues and charcoal. The pyrolysis normally occurs in the total absence of oxygen, while most gasification reactions take place in an oxygen-starved environment.

In a gasifier, the biomass or waste particle is exposed to high temperatures primarily generated from the partial oxidation of the carbon. As the particle is heated, the moisture is driven off. The moisture can range from below 10 percent to over 50 percent of the incoming fuel weight. Further heating of the particle begins to drive off the volatile gases.

The resulting producer gas can then be used in boilers or cleaned up and used in combustion turbines. The primary area of research for this technology is the scrubbing of the producer gas of tars and particulates at high

temperatures to protect combustion equipment downstream of the gasifier and still maintain high thermal efficiency.

## Technology Characteristics

### *Mass Burn*

Early incinerators were characterized by a very negative environmental image and very poor performance. Concerns over direct combustion, particularly gas and smoke emissions as well as the disposal of ash means that direct combustion technologies are governed by more stringent government scrutiny and approvals, thereby increasing the establishment cost of these projects.

Incinerators are often seen as a solution to the scarcity of urban landfill sites rather than as a means for efficient energy recovery from waste streams. "Incineration" is a generic term that encompasses a wide range of options that differ markedly in technology, economics and environmental impact.

The combined ash and air pollution control residue typically ranges from 20 percent to 25 percent by weight of the incoming refuse processed. This ash residue may or may not be considered a hazardous material, depending on the makeup of the municipal waste.

It may be possible to: (1) avoid the production of hazardous ash by preventing the sources which create hazardous waste from entering the system, or (2) treat the ash. Both of these methods avoid the costs of disposal at a limited number of landfills classified as able to handle hazardous materials.

### *Refuse-Derived Fuel (RDF)*

Several types of RDFs can be made, such as coarse, fluffy, powdered or densified, depending on the composition of the refuse, and the technology used. Typically, the MSW, after removal of non-combustibles, is comminuted by a flail mill. A magnetic separator then removes ferrous materials before screening out the larger particles. The remainder is shredded into small particles to make the RDF. RDF can be burned in dedicated boilers or co-fired with another fuel such as coal, or biomass (like wood or agricultural residues).

These products have significantly smaller volume than the original waste and thus have a higher volumetric energy density (VED) making them a more compact source of energy. They are also easier to transport and store than other forms of waste derived energy. RDF briquettes and pellets can be used directly. They can also be used in charcoal production. RDF pellets have a heat value of around 60 percent of coal.

*Thermal Gasification/Pyrolysis*

The following describes a three-stage gasification process:

1. *Pre-processing: Household* waste and organic materials are initially pre-treated by "pressure cooking" them with steam. This produces a sterilized pulp-like material that is filtered for any "hard" recyclables such as aluminum, glass or steel. These are separated at the plant and transported to other recycling facilities.
2. *Gasification:* The pulp is then fed into a gasifier that converts it into gases consisting mainly of carbon, hydrogen and oxygen without introducing any air. These gases are reformed into a clean "syngas" (synthetic fuel gas).
3. *Electrical Generation:* The syngas is then used to fuel a prime mover for electricity generation.

It is not economical to transport syngas over long distances; the power generation equipment must be sited near the gasification facilities.

### Natural Resource

Based on our research the total MSW generated at the installations of the Greater Fairbanks Military Complex is estimated to be roughly 1,200 tons a month. EAFB segregates about 60 to 65 tons/month of burnable paper for use as co-fired RDF at its CHPP. FGA segregates somewhat less than 10 tons/month of burnable waste (wood, paper, cardboard, etc.). The Cold Regions Test Center segregates very small amounts (less than 5 lb) of burnable waste each month (Table B5).

Table B5. Municipal solid waste information.

| Location | Monthly Average Volume (tons/month) | Composition | Moisture (%) | Caloric Value (Btu/ton) |
|---|---|---|---|---|
| Fort Wainwright | 150.3 | Housing Waste | Unknown | Unknown |
| Fort Wainwright | 233.53 | Non-Housing Waste | Unknown | Unknown |
| Eielson AFB | 291.63 | Refuse | Unknown | Unknown |
| Eielson AFB | 62.3 | RDF Paper | Unknown | 6,800 |

| Location | Monthly Average Volume (tons/month) | Composition | Moisture (%) | Caloric Value (Btu/ton) |
|---|---|---|---|---|
| Fort Greely Garrison | 8.81 | Burnable (Wood, Paper and Cardboard) | Unknown | Unknown |
| Fort Greely Garrison | 19.41 | Mixed | Unknown | Unknown |
| Fort Greely Garrison | 64.22 | Bulk | Unknown | Unknown |
| Fort Greely Garrison | 1.3 | Ash | Unknown | Unknown |
| Fort Greely Garrison | 5.21 cu yds | Asbestos | Unknown | Unknown |
| Fort Greely Garrison | 255.58 | Other (Sewage Sludge, Human Waste, Inert Debris) | Unknown | Unknown |
| CRTC | 47.33 cu yds | Burnable | Unknown | Unknown |
| CRTC | 66.17 cu yds | Non-Burnable | Unknown | Unknown |
| Fort Greely MDA | Unknown | Unknown | Unknown | Unknown |

## Technology Maturity

### *Mass Burn*

Present trends indicate a move away from single solutions (such as mass burn or landfill) towards the integration of more advanced incineration technologies within overall waste management strategies, based on setting priorities for waste treatment methods. These include waste minimization, recycling, materials recovery, composting, biogas production, energy recovery through RDF, and residual landfilling. This approach favors the integration of incineration within a range of complementary approaches. In the process, mass burn incineration tends to be replaced by more specific and efficient techniques such as RDF incineration, gasification or pyrolysis.

### *Refuse-Derived Fuel*

High temperature waste incineration is common in the north eastern United States where space limitations, high land costs and political opposition to locating landfills in communities, limit land disposal.

### *Thermal Gasification/Pyrolysis*

Both of these technologies are in the development stage with a limited number of units in operation. The Hyperion Energy Recovery System operated by the City of Los Angeles had a system designed to fire dried sewage sludge in a staged fluidized bed combustor. The resulting gas was then combusted in stages, and the heat was used to turn water into steam, driving a 10 MW steam turbine-generator.

### Technology Applications

The United States has about 100 operational MSW-fired power generation plants, representing a combined capacity of approximately 1,500 megawatts. However, because construction costs of new plants have increased, economic factors have limited new construction and no new capacity additions are projected.

Power plant size is often constrained by the availability of local feedstock and is generally less than 25 to 40 MW. However, by using dedicated feedstock supplies, such as the co-location of incinerators at waste disposal sites, the size can be increased to 50 to 75 MW, gaining significant economies of scale.

The incinerators required by different waste-energy combustion routes (mass burn, RDF, incineration, gasification, pyrolysis) are markedly different, and so are their costs and environmental impacts.

### Potential Installation in Interior Alaska

Numerous obstacles and factors may limit the growth of MSW power generation, including environmental regulations and public opposition to siting MSW facilities.

The Fairbanks North Star Borough conducted a comprehensive review of MSW management and disposal practices in the 1990s and chose not to pursue incineration or waste-to-energy. Among the reasons were limited quantities of waste, no economy of scale opportunities, and cost.

### Benefits

- MSW facilities are paid by the fuel suppliers to take the fuel (known as a “tipping fee”)
- MSW facilities typically have high capacity factors (85-90 percent) and provide baseload power.
- Decreased landfill requirements and possible improvements in groundwater quality versus decreased air quality from MSW combustion
- The plants and trees that make up the paper and food waste remove carbon dioxide from the air while they are growing, which is returned to the air when this material is burned. In contrast, when fossil fuels are burned, they release carbon dioxide that has not been part of the Earth’s atmosphere for a very long time (i.e., in a human time scale).

### Disadvantages

- MSW conversion facilities use basically the same steam-turbine technology found at wood waste facilities. However, installed capital costs are much greater because of the need for specialized MSW handling and waste separation equipment and stricter environmental emissions controls.
- Emissions from MSW combustion facilities include particulates, oxides of nitrogen, acid gases, metals, and organic compounds. These are regulated emissions. Odors are also a potential impact from MSW combustion.
- MSW facilities face much public opposition, and siting can be problematic.
- The variation in the composition of MSW raises concerns. For example, if MSW containing batteries and tires are burned, toxic materials are released into the air. A variety of air pollution control technologies have to be used to reduce most toxic air pollutants from MSW power plants.
- MSW ash must be sampled and analyzed regularly to determine whether it is hazardous or not.
- MSW permitting can be a long and difficult process.
- The MSW resource in the project area is very limited.
- High-temperature MSW processing requirements, associated with RDF and gasification technologies reduce overall waste-to-energy.

### Conclusion

Because there is insufficient military MSW to support a cost effective waste-to-energy installations, this technology is not considered further.

## Geothermal Power

### Technology Description

Geothermal energy is heat derived from the thermal energy contained in underground reservoirs of steam, hot water, and hot dry rocks, several miles below Earth's surface, and even farther down to the extremely high temperatures of molten rock called magma.

The current production of geothermal energy places it third among renewables, following hydroelectricity and biomass, and ahead of solar and wind. Current U.S. geothermal electric power generation totals approximately 2,200 MW.

Geothermal resources range from shallow ground to hot water and rock, and include:

- *Hot water or steam* extracted from geothermal reservoirs is used to supply steam turbine generators to produce electricity.
- *Moderate-to-low* temperature geothermal resources are used for direct-use applications such as district and space heating.
- *Lower* temperature, shallow ground, geothermal resources are used by geothermal heat pumps to heat and cool buildings.

The highest temperature resources are generally used only for electric power generation. Uses for low and moderate temperature resources can be divided into two categories: direct use and ground-source heat pumps. In this report we will only discuss geothermal power.

No fuel is burned in geothermal power plants. Geothermal power plants give off water vapor, but have no smoky emissions. There are three geothermal power plant types.

Flashed Steam Plants. Most geothermal power plants operating today are “flashed steam” power plants. Hot water from production wells is passed through one or two separators where, released from the pressure of the deep reservoir, part of it flashes (explosively boils) to steam. The force of the steam is used to spin the turbine generator. To conserve the water and maintain reservoir pressure, the geothermal water and condensed steam are directed down an injection well back into the periphery of the reservoir, to be reheated and recycled.

Dry Steam Plants. A few geothermal reservoirs produce mostly steam and very little water. Here, the steam shoots directly through a rock-catcher and into the turbine. The first geothermal power plant was a dry steam plant, built at Larderello in Tuscany, Italy in 1904. The Larderello dry steam fields are still producing electricity today. The Geysers dry steam reservoir in northern California has been producing electricity since 1960. It is the largest known dry steam field in the world and, after 40 years, still produces enough electricity to supply a city the size of San Francisco.

Binary Power Plants. In a binary power plant, the geothermal water is passed through one side of a heat exchanger, where the heat is transferred to a second (binary) liquid, called a working fluid, in an adjacent separate pipe loop. The working fluid boils to vapor which, like steam, powers the turbine generator. It is then condensed back to a liquid and used over and

over again. The geothermal water passes only through the heat exchanger and is immediately recycled back into the reservoir.

Although binary power plants are generally more expensive to build than steam-driven plants, they have several advantages: (1) The working fluid (usually isobutane or isopentane) boils and flashes to a vapor at a lower temperature than does water, so we can generate electricity from reservoirs with lower temperatures. This increases the number of geothermal reservoirs in the world with electricity-generating potential; (2) The binary system uses the reservoir water more efficiently. Since the hot water travels through an entirely closed system it results in less heat loss and almost no water loss, and (3) Binary power plants have virtually no emissions.

Hybrid Power Plants. In some power plants, flash and binary processes are combined. An example of such a hybrid system is in Hawaii, where a hybrid plant provides about 25 percent of the electricity used on the Big Island.

### Geothermal Resources in Alaska

Before the oil crash, both the Geophysical Institute and the Division of Geological and Geophysical Surveys (DGGS) did extensive studies of Alaska's geothermal potential, effectively mapping out the resources of the whole state (Figure B6). The most promising sites for power plants are known to be mostly in the Aleutians: Makushin, which is near Unalaska, and a spot on Akutan Island are both being looked at as serious possibilities.

The Alaska Department of Natural Resources' Division of Geological and Geophysical Surveys, has identified Makushin as the only Alaska site in with proven geothermal resources that would be able to serve a substantial population base in Unalaska. Akutan is much closer to the local village—the home of a major seafood plant—and would be simpler logistically.

From the map below, we can see geothermal resources that are closest to Fairbanks are located in Circle and Chena Hot Springs. According to Nye, "Interior sites such as Circle (and Manley Hot Springs) do not have hot enough water for power generation but can tame geothermal energy for domestic uses" and "Chena Hot Springs, on the other hand, has marginal potential but would require new technology to make it work."

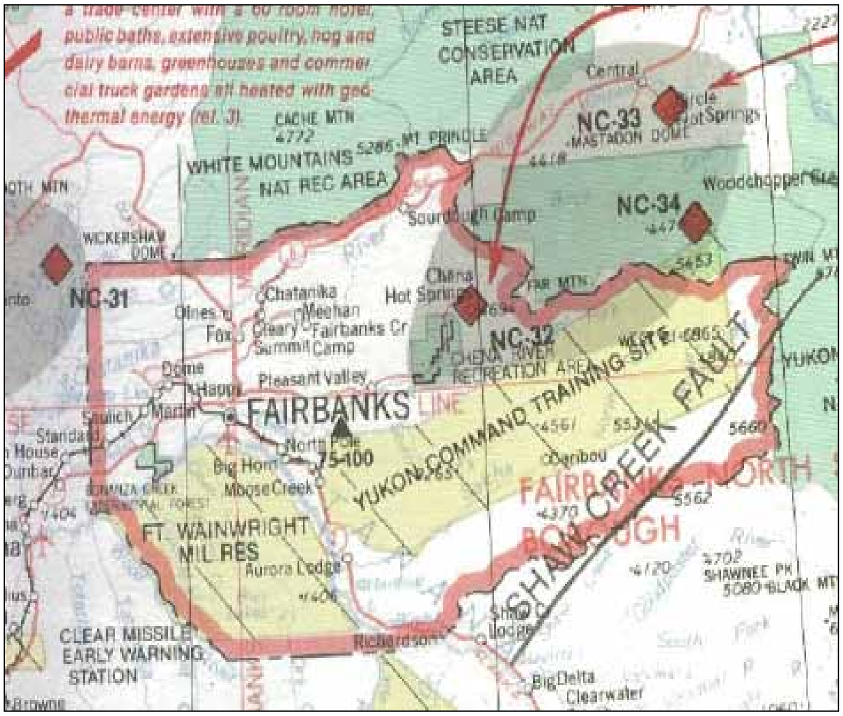


Figure B6. Geothermal resources in interior Alaska.

The USGS map of Alaskan geothermal resources indicates no known geothermal resources in the greater Fairbanks area.

At Circle, water from nine springs, with a maximum temperature of 140 °F and combined flow of 1,700 lpm, is used to heat a large hotel, swimming pool, and small greenhouse.

At Chena, water from 10 springs, with a combined flow of 840 lpm and maximum temperature of 135 °F, is used to heat a lodge and enclosed swimming pool.

Based on geothermometry, estimated reservoir temperatures for both sites are 266 °F to 293 °F.

## Technology Maturity

As of 1999, 8,217 megawatts of electricity were being produced from some 250 geothermal power plants running day and night in 22 countries around the world. These plants provide reliable base-load power for well over 60 million people, mostly in developing countries.

The three power plant technologies discussed above use only a tiny fraction of the total geothermal resource. Several miles everywhere beneath

Earth's surface is hot, dry rock being heated by the molten magma directly below it. Technology is being developed to drill into this rock, inject cold water down one well, circulate it through the hot, fractured rock, and draw off the heated water from another well. One day, it might also be able to recover heat directly from the magma.

Producing electricity from hot dry rock requires fracturing hot rocks, pumping water into and out of the hot rock, and generating electricity. Federal funding for research into energy recovery from hot dry rock has decreased to $1.7 million in fiscal year 1997, and the Hot Dry Rock Program is now being refocused to respond to industry needs. While demonstration of the approach has been successful, the technology remains uneconomical. Funding of energy extraction research has ended, primarily because equipment used to penetrate the magma is not certain to prevent a blowout, and a way to engineer the containment of such a high pressure, high-temperature blowout is unknown. Research continues in Japan and France, however.

### Potential Installations in Interior Alaska

In Alaska, 17 communities with geothermal resources have been identified. They are: Adak, Akutan, Baranof, Bell Island Hot Springs, Chena Hot Springs, Circle Hot Springs, Goddard, Makushin, Manley Hot Springs, Melozi Springs , Morzhovoi, Nancy, Portage, Pilgrim, Springs , Serpentine Hot Springs, Sitka, and Unalaska.

The Chena Hot Springs resource is suitable for domestic heating purposes only and is not close enough to the installations to be used cost-effectively.

### Benefits

There are many benefits associated with using Geothermal energy.

- Using geothermal energy is safe while its production uses limited surface area
- Geothermal energy is clean, renewable energy.
- Geothermal energy generates reliable and continuous baseboard power.
- Geothermal energy conserves fossil fuels and contributes to diversity in energy sources.
- Geothermal energy avoids importing and benefits local economy.

- Geothermal energy offers modular, incremental developments and village power to remote sites.

#### Disadvantages

- Geothermal power plants are still not cost competitive with traditional forms of energy.
- Geothermal resources are not always sufficient to support either a power production or heat generation, or either respective required capacity. For example, Fairbanks does not have any suitable sources for the area's power and heating needs.
- Reserves of hydrothermal energy in the United States are still difficult to quantify accurately because much exploration remains to be done.

#### Conclusion

USGC maps of geothermal resources indicate no known sources suitable for heat or power production for the installations in the Greater Fairbanks Military Complex (Figure B7).

### Biomass/MSW/Biomass Gases (for Gas-Fired Combustion Turbines)

#### Technology Description

*General*

Biomass is plant matter such as trees, grasses, agricultural crops or other biological material (Figure B8).

Biomass is a renewable source of energy. It can be used as a solid fuel, or converted into liquid or gaseous forms, for the production of electric power, heat, or chemicals or for use in vehicles.

With more than 7,000 MW of installed capacity, biomass is the second-most utilized renewable power generation resource in the United States The 37 billion kWh of electricity produced each year from biomass is more than the entire state of Colorado uses annually. Generating this amount of electricity requires around 60 million tons of biomass per year.

Biomass offers many environmental benefits. Carbon dioxide produced during combustion is balanced by re-absorption by the growing plants. Emissions of $SO_x$ and other air pollutants are negligible or, at least, as easily controlled as those from fossil fuels.

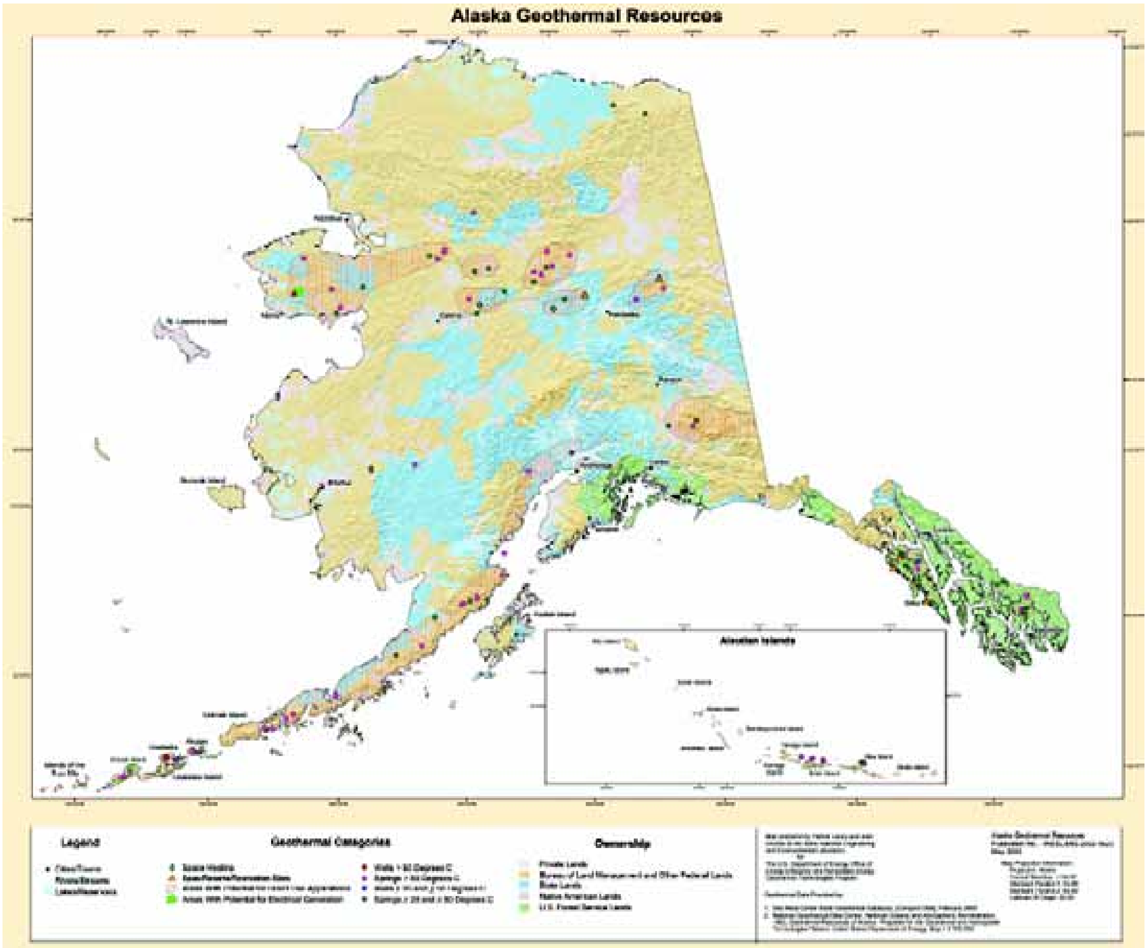



Figure B7. Map of geothermic resources in Alaska.

Figure B8. Common biomass sources.

*Converting Biomass to Energy*

Biomass can be used directly as fuel or converted to other forms for use as fuel or feedstock. Ultimately, biomass is more useful if converted to gaseous or liquid fuels, but the conversion process can cost as much as the collection of biomass and feedstock production.

*Gasification of Biomass*

Gasification of biomass is a two-step, endothermic (heat absorbing) process in which a solid fuel (in this case, biomass) is thermochemically converted into a low- or medium-Btu gas (Figure B9). In the first reaction, pyrolysis, the volatile components of the fuel are vaporized at temperatures below 1,100 °F by a set of complex reactions. Please refer to the Biomass Gasification Process Diagram on the next page.

Included in the volatile vapors are hydrocarbon gases, hydrogen, carbon monoxide, carbon dioxide, tar, and water vapor. Because biomass fuels tend to have more volatile components (70-86 percent on a dry basis) than coal (30 percent), pyrolysis plays a larger role in biomass gasification than in coal gasification. Char (fixed carbon) and ash are the pyrolysis by-products which are not vaporized. In the second step, the char is gasified through reactions with oxygen, steam, and hydrogen. Some of the unburned char is combusted to release the heat needed for the endothermic gasification reactions.

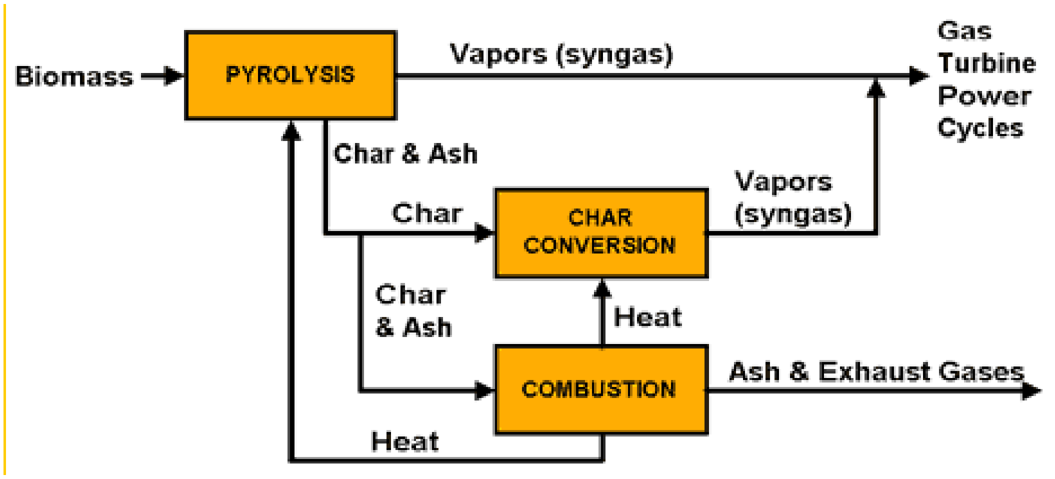



Figure B9. Biomass gasification process diagram.

### Technology Characteristics

*Biomass Materials—Feedstocks*

Biomass materials that are byproducts from activities such as wood products manufacturing, construction, agriculture, and forest harvesting or management are referred to as "residues."

Residues are the most economical biomass fuels for generating electricity. These are the organic byproducts of food, fiber, and forest production. Examples include sawdust, rice husks, and bagasse (the residue remaining after juice has been extracted from sugar cane). Used shipping pallets and yard trimmings are low cost sources of biomass and are common near population and manufacturing centers.

Woody biomass is concentrated in the Southeast, Northeast, Pacific Northwest, and Upper Great Lakes regions. Herbaceous/grassy biomass is plentiful in the Midwest states, while cropland is concentrated in the upper Midwest, Lower Great Lakes region, and Mississippi delta. Research is currently underway to improve energy crops that are well-suited to regional climate conditions throughout the United States

In the future, much larger quantities of biomass power could come from fast-growing trees and crops (called "energy crops"), forest debris and thinnings, agricultural wastes, animal manure, and non-hazardous wood debris diverted from landfills.

Wood is the most commonly used biomass fuel for heat and power. The most economic sources of wood fuels are usually urban residues and mill residues.

Urban residues used for power generation consist mainly of chips and grindings of clean, non-hazardous wood from construction activities, woody yard and right-of-way trimmings, and discarded wood products such as waste pallets and crates. Local governments can encourage segregation of clean wood from other forms of municipal waste to help ensure its re-use for mulch, energy, and other markets. Using clean and segregated biomass materials for electricity generation recovers their energy value while avoiding landfill disposal.

Mill residues, such as sawdust, bark, and wood scraps from paper, lumber, and furniture manufacturing operations are typically very clean and can be used as fuel by a wide range of biomass energy systems.

Forest residues include underutilized logging residues, imperfect commercial trees, dead wood, and other non-commercial trees that need to be thinned from crowded, unhealthy, fire-prone forests. Because of their sparseness and remote location, these residues are usually more expensive to recover than urban and mill residues.

Agricultural residues are the biomass materials remaining after harvesting agricultural crops. These residues include wheat straw, corn stover (leaves, stalks, and cobs), orchard trimmings, rice straw and husks, and bagasse (sugar cane residue). Due to the high costs for recovering most agricultural residues, they are not yet widely used for energy purposes; however, they can offer a sizeable biomass resource if supply infrastructures are developed to economically recover and deliver them to energy facilities.

Energy crops are crops developed and grown specifically for fuel. These crops are carefully selected to be fast growing, drought and pest resistant and readily harvested alternative crops. Energy crops include fast-growing trees, shrubs, and grasses such as hybrid poplars, hybrid willows, and switchgrass, respectively. In addition to environmental benefits, energy crops can provide income benefits for farmers and rural landowners.

*Gasifier Technology Options*

The gasification process oxidant can be either atmospheric air or pure oxygen. Oxygen-blown gasifiers offer a higher-Btu gas and faster reaction rates than air-blown systems, but have the disadvantage of additional capital costs associated with the oxygen plant.

Currently, the preferred equipment for biomass integrated gasifier power systems is the air-blown gasifier which produces a gas diluted with nitrogen from the atmosphere.

A second consideration for gasifiers is the choice between dry-ash and slagging gasifier designs. The slagging gasifier requires substantially less blast steam injection for the gasification process and, because it operates at higher temperatures, the gasifier has the potential for greater throughput capacity.

There are also alternative methods for transferring the heat from char combustion to the gasifier feedstock. In direct combustion gasifiers, the char is burned in the vessel where thermochemical reactions occur. Indirect gasifier systems, on the other hand, utilize a separate reactor for char combustion from which heat is transferred to the gasifier reactor. With the latter system, nitrogen from the atmosphere and the combustion process is kept from combining with, and subsequently diluting, the product gas.

### Resource

There is limited biomass resource in the interior of Alaska for harvest. During winter season, most of the above resources would not be available.

### Technology Maturity

With an estimated 14,000 MW of annual worldwide installed generation capacity, biomass power is the largest source of non-hydro renewable electricity in the world. The United States is the largest biomass generator. In the future, the continued need for on-site industrial power, waste reduction, stricter environmental regulations, and rising consumer demand for renewable energy will provide the main impetus for the industry's growth.

Worldwide biomass generation is expected to grow to more than 30,000 MW by 2020.

Recent studies indicate that additional (presently unused) quantities of economically available biomass may exceed 39 million tons per year in the United States—enough to supply about 7,500 MW of new biomass—a doubling of the existing U.S. biomass capacity.

### Technology Applications

Woody biomass is concentrated in the Southeast, Northeast, Pacific Northwest, and Upper Great Lakes regions. Herbaceous/grassy biomass is plentiful in the Midwest states, while cropland is concentrated in the upper Midwest, Lower Great Lakes region, and Mississippi delta. Research is currently underway to improve energy crops that are well suited to regional climate conditions throughout the United States

### Size

Biomass power systems range in size from a few kW (enough for an average U.S. home) up to 80 MW power plants.

### System Costs and Considerations

The cost to generate electricity from biomass depends on the type of technology used, the size of the power plant, and the cost of the biomass fuel supply.

In today's direct-fired biomass power plants, generation costs are about 9¢/kWh. Advanced technologies such as gasification-based systems could generate power in the future for as little as 5¢/kWh.

### Potential Installation in Interior Alaska

Although the technology appears to be attractive in summer time, cold weather conditions in Alaska make the biomass gasification process inappropriate due to both a lack of biomass resources and significant process heat requirements.

### Benefits

- Biomass is a renewable resource.
- Gasification is a process step that produces a more easily used fuel form for fuel and provides the means to remove fuel contaminants that can cause problems for downstream power generation equipment.
- Gasification gives biomass the flexibility to fuel a wide range of power systems: gas turbines, fuel cells, and reciprocating engines.
- A wide variety of biomass materials can be gasified, many of which would be difficult or impossible to burn otherwise.
- Gasification offers a means of processing waste fuels, many of which are problematic.
- Gasification is an alternative to disposal in landfills.
- It is easier to distribute and control a gaseous fuel.
- Gasification coupled with advanced conversion cycles reduces air emissions per kWh of electricity produced.

### Disadvantages

- Biomass has a lower energy content than other fuels and the delivery costs might be higher because of the dispersed nature of the resource. Generally, biomass must be procured within a 50-mile radius of the power plant to be economical.
- Cold winter makes heat requirements for digesters very expensive.
- Limited biomass resources are available in winter time.

### Conclusion

The large quantities of biomass required to generate power are not available in wintertime. In addition, winter heat requirements for the digesters would greatly reduce the overall efficiency. This option is not recommended as a viable alternative for further consideration.

## Fuel Cells

Much of the following information regarding fuel cells came from dodfuelcells.com.

### Technology Description

A fuel cell is an electrochemical energy conversion device that converts fuel and oxygen into water, producing electricity and heat in the process. It is very much like a battery that can be recharged while you are drawing power from it (Figure B10.9). Instead of recharging using electricity, however, a fuel cell uses hydrogen and oxygen. Because electrical energy is generated without combusting fuel, fuel cells are extremely attractive from an environmental standpoint.

All fuel cells have the same basic operating principle. An input fuel (hydrogen) is catalytically reacted (electrons removed from the fuel elements) in the fuel cell to create an electric current.

Fuel cells consist of an electrolyte material, which is sandwiched in between two thin electrodes (porous anode and cathode). The input fuel passes over the anode (and oxygen over the cathode) where it catalytically splits into ions and electrons. The electrons go through an external circuit to serve an electric load while the ions move through the electrolyte toward the oppositely charged electrode. At the electrode, ions combine to create by-products, primarily water and $CO_2$.

Depending on the input fuel and electrolyte, different chemical reactions will occur.

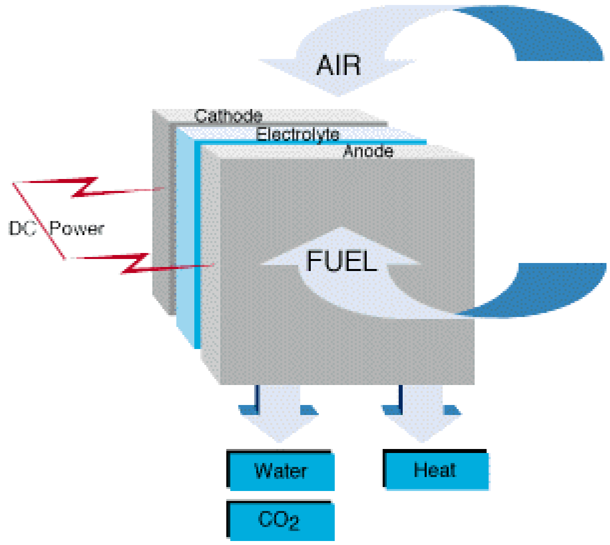



Figure B10. Fuel cell technology.

Fuel cells are typically grouped into three sections: (1) Fuel Processor, (2) Power Section (fuel cell stack), and (3) Power Conditioner (Figure B11).

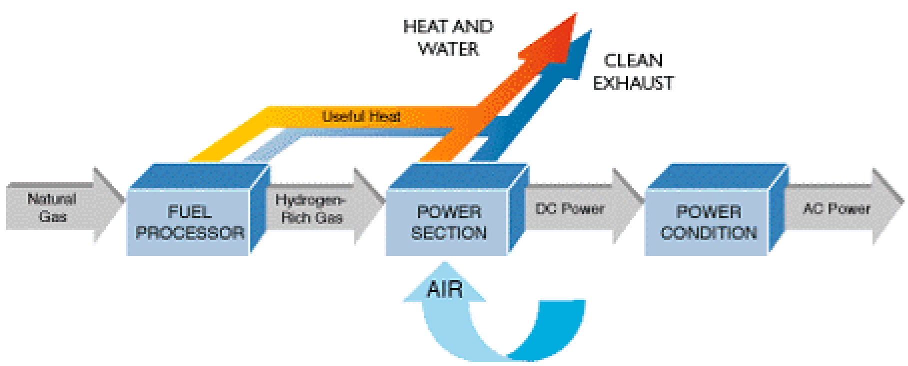



Figure B11. Fuel cell sections.

In the fuel processor, a fuel such as natural gas is reformed to boost the concentration of hydrogen. The hydrogen rich fuel and oxygen (air) then feed into the power section to produce direct-current (DC) electricity and reusable heat. The power section includes a fuel cell stack, which is a series of electrode plates interconnected to produce a set quantity of electrical power. The output DC electricity is then converted to AC electricity in the power conditioning section where it also reduces voltage spikes and harmonic distortions.

## Technology Characteristics

The oxygen required for a fuel cell generally comes from the air. The hydrogen is not so readily available, however. Hydrogen has some limitations that make it impractical for use in most applications. Because hydrogen is

difficult to store and distribute, it would be much more convenient if fuel cells could use fuels that are more readily available.

This problem is addressed by a device called a reformer. A reformer turns hydrocarbon or alcohol fuels into hydrogen, which is then fed to the fuel cell. Unfortunately, reformers are not perfect. They generate heat and produce other gases besides hydrogen. They use various devices to try to clean up the hydrogen, but even so, the hydrogen that comes out of them is not pure, and this lowers the efficiency of the fuel cell. The more promising fuels that are used today are natural gas, propane and methanol.

There are four primary types of fuel cells:

1. *Phosphoric Acid Fuel Cell (PAFC).* The phosphoric-acid fuel cell has potential for use in small stationary power-generation systems. It operates at a higher temperature than PEM fuel cells, so it has a longer warm-up time. This makes it unsuitable for use in cars
2. *Molten Carbonate Fuel Cell (MCFC).* These fuel cells are also best suited for large stationary power generators. They operate at 1,100 °F, so they also generate steam that can be used to generate more power. They have a lower operating temperature than the SOFC, which means they do not need such exotic materials. This makes the design a little less expensive.
3. *Solid Oxide Fuel Cell (SOFC).* These fuel cells are best suited for large-scale stationary power generators that could provide electricity for factories or towns. This type of fuel cell operates at very high temperatures (around 1,800 °F). This high temperature makes reliability a problem, but it also has an advantage: The steam produced by the fuel cell can be channeled into turbines to generate more electricity. This improves the overall efficiency of the system.
4. *Proton Exchange Membrane Fuel Cell (PEMFC).* PEMFCs operate at a fairly low temperature (about 176 °F), which means they warm up quickly and do not require expensive containment structures. Constant improvements in the engineering and materials used in these cells have increased the power density to a level where a device about the size of a small piece of luggage can power a car.

The MCFC fuel cell, which is often used for large power generation is described in detail below.

## Molten Carbonate Fuel Cells

The MCFC uses a molten carbonate salt mixture as its electrolyte. The composition of the electrolyte varies, but usually consists of lithium carbonate and potassium carbonate. At the operating temperature of about 1200 °F, the salt mixture is liquid and a good ionic conductor. The electrolyte is suspended in a porous, insulating and chemically inert ceramic (LiA102) matrix (Figure B12).

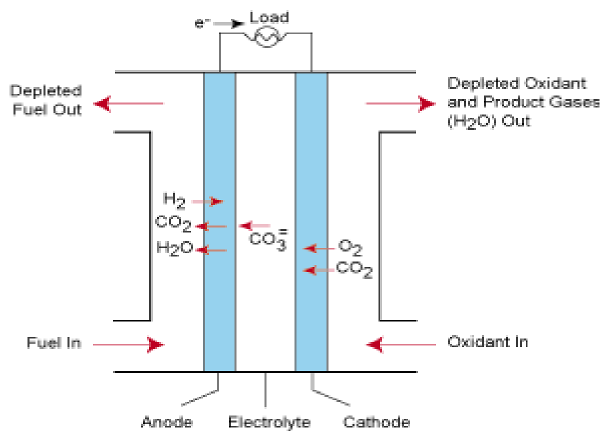


Figure B12. Molten carbonate fuel cell technology.

Figure 13 illustrates the MCFC reactions.

Anode reaction: $H_2 + CO_3^= \rightarrow H_2O + CO_2 + 2e^-$

$CO + CO_3^= \rightarrow 2CO_2 + 2e^-$

Cathode reaction: $O_2 \rightarrow 2CO_2 + 4e^- \rightarrow 2CO_3^=$

Figure B13. MCFC reactions.

The anode process involves a reaction between hydrogen and carbonate ions (CO3=) from the electrolyte which produces water and carbon dioxide ($CO_2$) while releasing electrons to the anode. The cathode process combines oxygen and $CO_2$ from the oxidant stream with electrons from the cathode to produce carbonate ions, which enter the electrolyte. The need for $CO_2$ in the oxidant stream requires a system for collecting $CO_2$ from the anode exhaust and mixing it with the cathode feed stream.

As the operating temperature increases, the theoretical operating voltage for a fuel cell decreases and with it the maximum theoretical fuel efficiency. On the other hand, increasing the operating temperature increases the rate of the electrochemical reaction and thus the current that can be obtained at a given voltage. The net effect for the MCFC is that the real oper-

ating voltage is higher than the operating voltage for the PAFC at the same current density.

The higher operating voltage of the MCFC means that more power is available at a higher fuel efficiency from a MCFC than from a PAFC of the same electrode area. As size and cost scale roughly with electrode area, this suggests that a MCFC should be smaller and less expensive than a “comparable” PAFC.

The MCFC also produces excess heat at a temperature that is high enough to yield high-pressure steam that may be fed to a turbine to generate additional electricity. In combined cycle operation, electrical efficiencies in excess of 60 percent (HHV) have been suggested for mature MCFC systems.

The MCFC operates at between 1,110 °F and 1,200 °F, which is necessary to achieve sufficient conductivity of the electrolyte. To maintain this operating temperature, a higher volume of air is passed through the cathode for cooling purposes.

As mentioned above, the high operating temperature of the MCFC offers the possibility that *it could operate directly on gaseous hydrocarbon fuels such as natural gas*. The natural gas would be reformed to produce hydrogen within the fuel cell itself.

The need for $CO_2$ in the oxidant stream requires that $CO_2$ from the spent anode gas be collected and mixed with the incoming air stream. Before this can be done, any residual hydrogen in the spent fuel stream must be burned. Future systems may incorporate membrane separators to remove the hydrogen for recirculation back to the fuel stream.

At cell operating temperatures of 1,200 °F noble metal catalysts are not required. The anode is a highly porous sintered nickel powder, alloyed with chromium to prevent agglomeration and creep at operating temperatures. The cathode is a porous nickel oxide material doped with lithium. Significant technology has been developed to provide electrode structures which position the electrolyte with respect to the electrodes and maintain that position while allowing for some electrolyte boil-off during operation. The electrolyte boil-off has an insignificant impact on cell stack life. A more significant factor of life expectancy has to do with corrosion of the cathode.

The MCFC operating temperature is about 1,200 °F. At this temperature the salt mixture is liquid and is a good conductor. The cell performance is sensitive to operating temperature. A change in cell temperature from 1,200 °F to 1,110 °F results in a cell voltage drop of almost 15 percent. The reduction in cell voltage is due to increased ionic and electrical resistance and a reduction in electrode kinetics.

### Technology Maturity

The following are the examples of developing small and large fuel cell technologies, and a hybrid of fuel cell and unfired gas turbine.

FuelCell Energy's products are called Direct FuelCells because they can use hydrocarbon fuels without the need to first create hydrogen in an external fuel processor. The Fuel Cell Energy's single matched module power plant (Table B6) contains two power modules, each with four Direct FuelCell® stacks. The field trial units have a nominal output of 2 MW, and are designed for larger commercial and industrial settings where power quality, reliability, and possible cogeneration are important.

Table B6. Fuel Cell Energy's single matched module power plant capacities.

| Plant Specifications | | |
|---|---|---|
| Power Output | Efficiency (LHV) | Heat Rate |
| 2000 kW | 50% | 6,824 Btu/kWh LHV |

Fuel Cell Energy has also developed a hybrid concept combining the Direct Fuel Cell (DFC®) and an unfired gas turbine. This hybrid system uses a network of heat exchangers to transfer waste heat from the DFC system to the turbine, which converts a portion of the waste heat to mechanical energy and then electricity. The system adds 10 to 15 percentage points to the efficiency of the DFC. For large systems in the long term, unsurpassed net electric efficiency of close to 80 percent is possible.

In the nearer term, it is believed that cost effective small MW class hybrid systems can be configured with efficiencies of 70 percent or better. Although power plants utilizing this system are not yet available, the design is showing promise in its development stage. Under a Department of Energy-supported Vision21 program, activities are underway to operate a subscale system and to develop an ultra-high-efficiency 40 MW power-plant design.

### Technology Applications

#### Size

Although the fuel cell size varies from 1kW to 2 MW, commercially available applications are still rated low, not exceeding 250 kW

#### Utility-Connected Systems

On the stationary side, fuel cells are ideal for power generation, either connected to the electric grid to provide supplemental power and backup assurance for critical areas, or installed as a grid-independent generator for on-site service in areas that are inaccessible by power lines.

#### System Costs and Considerations

One company commercially offers fuel cell power plants for about $4,000 per kilowatt. At that price, the units are competitive in high value, “niche” markets, and in areas where electricity prices are high and natural gas prices low.

An (unpublished) study by Arthur D. Little, Inc., predicted that when fuel cell costs drop below $1,500 per kilowatt, they will achieve market penetration nationwide.

#### Potential Installation in Alaska

Although fuel cells are a clean power source, they require a clean fuel and are susceptible to contamination and electrode poisoning. The fuel needs to be converted to hydrogen; most hydrogen in the United States is produced from natural gas, which has limited availability in the Fairbanks area. Therefore, fuel cell technology is not recommended.

#### Permitting

Permitting for fuel cell technologies will be similar to that for the gas-fired turbines and boilers. Given fuel cell’s lower emissions, air quality permitting might be easier to obtain.

#### Benefits

Typical fuel cell benefits include:

- high energy conversion efficiency

- modular design
- very low chemical and acoustical pollution
- fuel flexibility
- cogeneration capability
- rapid load response.

Another advantage is the short lead-time required to build a fuel-cell powerplant. Because fuel cell systems are modular, they can be built at a factory and assembled at the site. Installation can be accomplished in many locations, including areas where both available space and water are limited.

Fuel Cell Energy, which is the leader in the today's fuel cell industry, promotes their large DFC's power plant technologies, which are advertised as the most efficient fossil fuel generators in this size range. Also:

- DFC's are virtually pollution free, allowing for easy siting.
- DFC's are quiet, making them friendly neighbors.
- DFC's power plants produce high quality electricity
- DFC's can operate on a variety of fuels, for use in a wide range of applications and settings.

#### Disadvantages

Many technical and engineering challenges remain that prevent fuel cell technology from being used commercially. Scientists and developers are hard at work on them. The main fuel cell disadvantages today are as follows:

- Fuel cells are still too expensive.
- Not enough fuel cells are being made to allow economies of scale.
- Fuel cells require clean fuel feedstock and are susceptible to impurity contamination.

#### Conclusion

While fuel cells are a clean power source, they require a clean fuel, such as natural gas, which has limited availability in the Fairbanks area. Current fuel cell technologies are still at the demonstration stage and are relatively small power applications. As a result, this technology is not considered ready for application at the GFMC installations.

## Hydropower

### Technology Description

Hydropower is one of the oldest forms of electric power generation. Hydropower is currently the largest source of renewable power, generating nearly 10 percent of the electricity used in the United States.

The most common type of hydropower plant uses a dam on a river to store water in a reservoir. Water released from the reservoir flows through a turbine, spinning it, which, in turn, activates a generator to produce electricity. But hydropower does not necessarily require a large dam. Some hydropower plants just use a small canal to channel the river water through a turbine.

The following are hydropower plant types used in the United States and worldwide:

- *Impoundment Hydropower*—An impoundment facility, typically a large hydropower system, uses a dam to store river water in a reservoir. The water may be released either to meet changing electricity needs or to maintain a constant reservoir level. (See below)
- *Run-of-River Projects*—utilize the flow of water within the natural range of the river, requiring little or no impoundment.
- *Microhydropower Projects*—produce 100 kilowatts (kW) or less. Microhydro plants can utilize low heads or high heads.
- *Diversion Hydropower*—channels a portion of the river through a canal or penstock, but may require a dam.
- *Pumped Storage*—another type of hydropower plant, which can even store power. It pumps water from a lower reservoir to an upper reservoir at times when demand for electricity is low. During periods of high electrical demand, the water is released back to the lower reservoir to generate electricity.

There are numerous pumped hydro plants in the United States. Some plants require a large, above-ground reservoir while others store water underground. Above-ground reservoirs have become difficult to site, and underground storage is only economical in very large units.

### Natural Resource

Generally, a site/state must have both a large volume of flowing water and a significant change in elevation to consider hydropower as a viable source of power.

Alaska has a relatively average resource as a percentage of the state's electricity generation. Alaska could produce over 10 million MWh of electricity annually from hydropower (see chart below). Interior Alaska climatic conditions make hydropower generally unavailable during the wintertime due to freeze-up.

### Technology Maturity

Hydropower is generally regarded as a very mature technology and represents the largest single renewable resource in the world.

Hydropower can have undesirable environmental effects, such as fish passage, fish injury and mortality from turbine passage, changes in water quality, inundation of land, and altering of ecosystems.

### Technology Applications

Figure B14 shows hydropower currently used within the United States.

Hydroelectric generation capacity can vary from a few kW to thousands of kW depending on the water and head available.

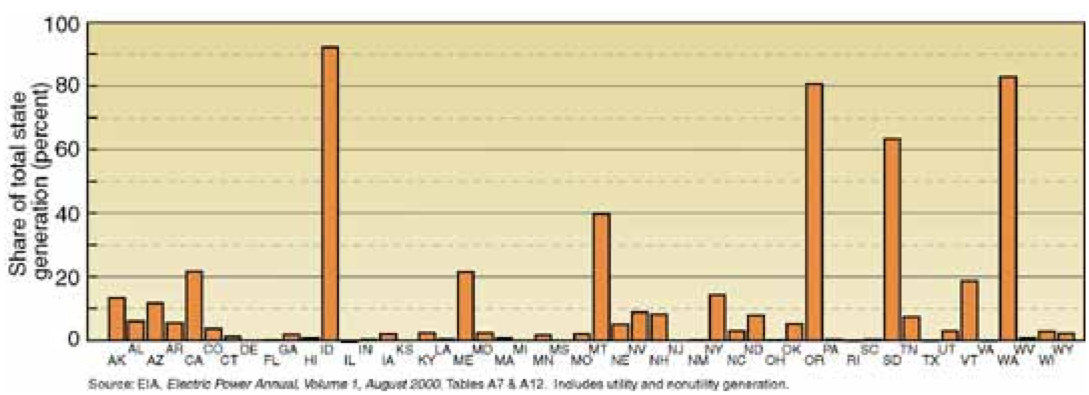



Figure B14. Hydroelectric net generation by state.

### System Costs and Considerations

The essentially free fuel and long economic life of the projects offset the relatively high capital cost for hydropower generation. Figure B15 shows average kilowatt-hour production costs, including fuel, power generation, and maintenance costs for the same technologies.

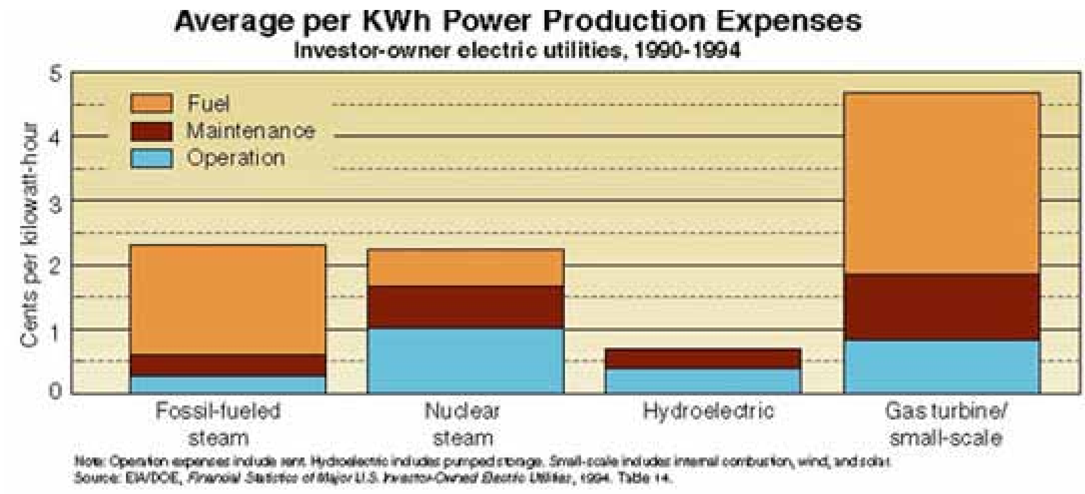



Figure B15. Average kilowatt-hour production costs for comparable technologies.

### Potential Installation in Interior Alaska

Technically, given a steady year-round source of running water, water generators can provide a constant and reliable alternative power source during summer time. However, special precautions need to be taken in Alaska to protect the turbine during winter freeze-up and spring break-up. Also, measures must be taken to keep the system from freezing during winter.

In 1997, a statewide Rural Hydroelectric Assessment and Development Study was conducted. The Study compiled information about 1,144 potential sites statewide. After an initial screening for obvious technical or environmental flaws and the development of preliminary benefit cost ratios for each site, the list was reduced to 131 sites with benefit cost ratios greater than 1. Of these 131 sites, 35 were in the “Yukon” statistical area. Of these 17 sites, the largest was 2.5 MW. Fourteen of the sites were smaller than 400 kW. None of the 17 survived a further economic screening to determine potential feasibility. This suggests that hydropower in interior Alaska is limited by resource availability.

Hydropower development is much more prevalent in southeast Alaska. For projects of sufficient size that are located in the Railbelt area, there is

the ability to transmit the power to GVEA over the Intertie. An excellent example of this is Bradley Lake, a project in which GVEA participates.

### Permitting

Hydro licensing is a complex and lengthy regulatory process—on average, it takes 10 years to license a project, some as long as 20 years. A number of Federal laws and regulations, as well as some state laws and regulations, govern the way in which decisions are made and establish the procedures that must be followed. In addition, many governmental agencies are responsible for administering and enforcing these laws and regulations during a licensing process. This long lead time can discourage the pursuit of almost all hydropower projects, particularly those involving large dams and reservoirs or those on streams with significant fishery resources.

To our knowledge, there no significant hydropower projects being pursued in Alaska at this time.

### Benefits

- The most important benefit of hydropower is its provision of clean, renewable energy.
- Generally it is a secure domestic resource, especially when compared to oil.
- Hydropower provides an economical means of regulating electric system operations. Hydropower facilities can quickly respond to changes in load and loss of other generation and as result are an excellent source of spinning reserves for a system. Hydropower can also provide economical “peaking” capability, subject to environmental operating constraints.
- Hydroelectric projects can also provide other vitally important benefits. These may include some combination of flood control, irrigation, navigation, recreation and water supply.

### Disadvantages

- Like any energy resource, there are environmental and other concerns. These include:
  Barriers to upstream and downstream fish passage
  Changes to water quality,
  Habitat condition,
  Instream flow rates

Loss of wetlands, scenic areas and archeological sites
Dam safety concerns

- Hydropower plant is difficult to permit
- Hydropower entails high initial capital costs
- Hydropower is not a reliable year-around primary power source in interior Alaska

### Conclusion

While hydropower development has obvious benefits, the lengthy permitting process and interior Alaska weather conditions eliminate it as a viable option.

## Integrated Gasification Combined Cycle (IGCC)

### Technology Description

The integrated coal gasification combined cycle (IGCC) technology is another alternative to conventional coal-fired plants.

In the IGCC process, coal is mixed with air and steam at high temperatures, which causes the coal to gasify to a mixture of hydrogen, carbon monoxide, and hydrogen sulfide, called syngas. The ash is separated and disposed of or used. The sulfur in the coal is converted into hydrogen sulfide, which eventually can be converted to elemental sulfur or some solid waste material. The cleaned gas is burned in a combustion turbine. The hot exhaust gases that exit the combustion turbine generate steam, which can then drive a steam turbine to produce electricity.

The combined cycle portion of the plant is similar to a conventional combined cycle, and its name "combined cycle" refers to the use of both gas-fueled combustion and steam turbines in the system. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 250-300 Btu/scf gas and steam production via heat recovery from the raw gas in addition to the combustion turbine exhaust (HRSG).

Specifics of a plant design are influenced by the gasification process, degree of heat recovery, and methods to clean-up the gas. Figure B16 shows a process diagram from a DOE Fact Sheet for the Polk County, FL. IGCC facility operated by Tampa Electric. The Texaco gasification process is used for the Polk County Plant. The diagram represents the current design. The

original design included more extensive heat recovery from the raw gas and the demonstration of hot gas clean up on part of the raw gas stream. The current design sacrificed some efficiency for more reliable performance.

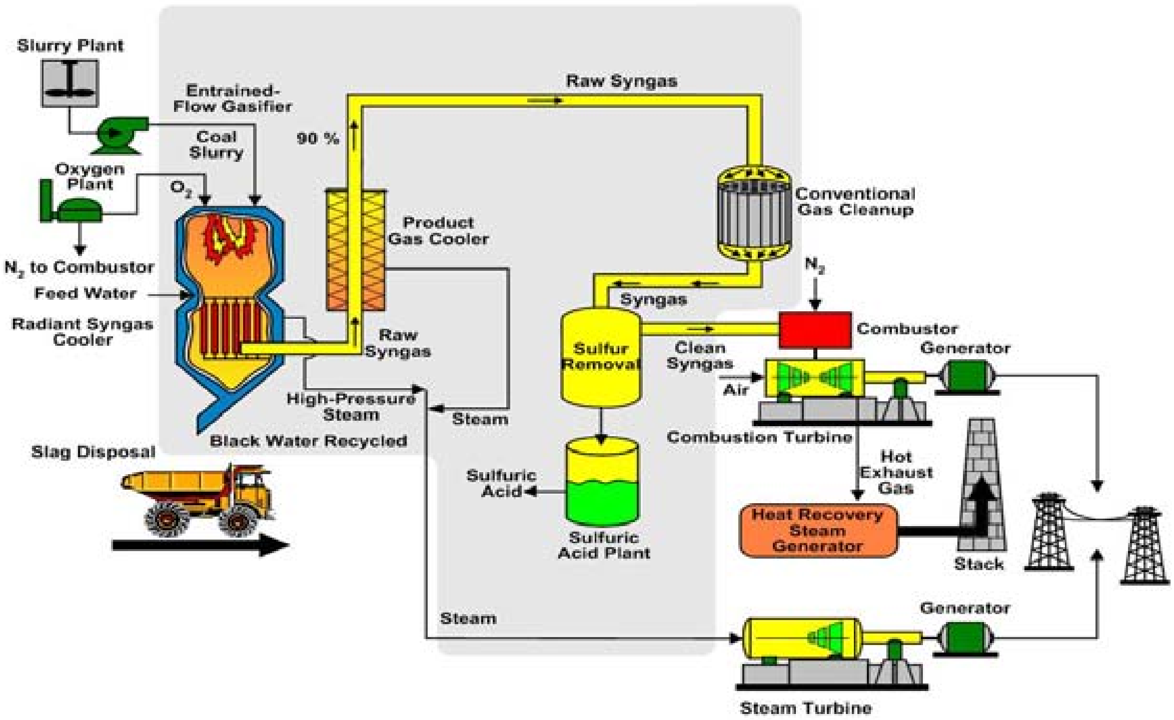



Figure B16. IGCC process diagram from for Polk County, FL.

## Technology Characteristics

IGCC technology has been demonstrated in a few commercial-scale facilities. A variety of coals have been gasified, the resulting gas has been cleaned up to allow use in combustion turbines, and electricity has been generated. However, the capital cost and performance in a number of areas have not been as attractive as planned.

The troublesome areas for IGCC have included high temperature heat recovery and hot gas cleanup. An important part of achieving an attractive heat rate is generation of high pressure and temperature steam from the high temperature raw gas. The temperature of the raw gas, however, is dependent on the coal gasification process and the coal properties.

Slagging gasifiers typically generate gases in the 2500 to 2800 °F range. These high temperature gases containing corrosive compounds such as $H_2S$ create a very demanding environment for the generation of high pres-

sure and temperature steam. The reliable generation of steam under these conditions has not been demonstrated in a commercial application.

Alternatives not recovering the heat in the raw gas, such as direct quenching of the gas, result in lower efficiencies. It is also attractive from an efficiency perspective to provide clean gas to the combustion turbine at an elevated temperature without cooling and re-heating, hence the desire to use hot gas clean up. Again, this demanding service has not been reliably demonstrated in a commercial application, resulting in less efficient approaches being used for current plants.

### Natural Resource

Sub-bituminous coal is available in large quantities in the interior of Alaska and can provide a long-term source of fuel.

### Technology Maturity

The current and near-term IGCC plants must be viewed as technically feasible, but not delivering the cost and performance to be economically attractive. The current IGCC plants are providing good information about the technology, but not demonstrating the necessary cost of electricity to expect the technology to be commercially available at this time.

### Life Expectancy and Life Cycle Cost

The combined cycle portion of the plant is obviously attractive from a capital cost perspective compared to a conventional coal plant, but added gasification, coal feeding, gas cooling, gas clean-up, oxygen plant, etc. result in significant costs, resulting in a higher first cost than for a conventional coal plant.

The higher efficiency than a conventional coal plant could justify the higher capital costs. The currently demonstrated capital cost is about 30 percent higher and efficiency is about 5 percent better. This cost and performance do not result in a lower cost of electricity than a conventional coal plant. The reported cost for the Polk County IGCC Plant is about \$1800/kW and the NPHR (net plant heat rate) target at full load is 9,400 Btu/kWh. The annual NPHR has ranged from 9,877 Btu/kWh to 10,725 Btu/kWh. The target for IGCC NPHR in the future is about 8,000 Btu/kWh.

Future capital costs are expected to be about the same as conventional coal units of similar size. When those conditions are realized, IGCC should be a cost effective alternative to conventional coal.

### Technology Applications

*Demonstrations*

One of the biggest IGCC demonstration projects was the 100-MW Cool Water Plant located in Daggett, California. It began operating in 1984.

DOE has a program, Vision 21, with the goal of providing clean coal power generation alternatives that includes improving IGCC cost competitiveness. However, at this time, it is hard to predict the final DOE findings and recommendations and to assume that IGCC will provide cost competitive electric power.

### Size

IGCC equipment sizes generally vary from 100-MW (smaller units) to 500-MW and higher (larger units). It is apparent that IGCC technology is more attractive for large-scale utility applications.

### System Costs and Considerations

Capital costs for an IGCC system could range from $1,200 to $2,350/kWe (net). For smaller units (250-MW range), costs are expected to be higher, about $1,600 per kWe. The Electric Power Research Institute (EPRI) estimates a plant cost of $1,630/kWe for a 500-MW IGCC. The gas production and purification facilities will account for about 40 percent of total costs. Operating and maintenance costs could range from 6 to 12 mills/kilowatt hour (kWh).

### Permitting

Given a lack of IGCC applicability in Alaska, a discussion of permitting issues is not warranted.

### Benefits

An IGCC system's major advantages are as follows:

- very low rate of emissions
- fuel efficiency
- requires less water than a conventional coal-fired steam plant; the modular design makes construction time shorter.

### Disadvantages

Fuel gas treatment is one of the areas where additional research is needed.

- Hot gas cleanup systems remove sulfur and nitrogen compounds and particulate from the fuel gas without cooling and then re-heating the gas. These compounds are very abrasive and must be removed to prevent turbine blade and component failure.
- Existing gas cleanup technology must operate at relatively cool temperatures. Although switching from a cold- to hot-gas cleanup system could increase efficiency by 3.6 percent, many difficult technological problems must be overcome.
- The high temperature gases containing corrosive compounds such as $H_2S$ create a very demanding environment for the generation of high pressure and temperature steam. The reliable generation of steam under these conditions has not been demonstrated in a commercial application.

### Conclusion

IGCC is a technology with the potential to produce energy from coal with a higher efficiency and lower emissions than conventional coal burning technologies. Currently there are only two utility scale demonstration projects with DOE participation. These projects continue to provide data and produce electricity as part of day-to-day operations for the participating utilities. However, the cost, performance, and emissions of the units have not been as attractive as necessary to compete with current conventional technologies.

The technology also requires much larger facility than that involved in this study to produce favorable economics. Therefore, IGCC technology is not considered further in this study.

## Coal Gasification (for gaseous boiler fuel)

### Technology Description

Gasification is the chemical process for converting any carbon containing material, solid (coal) or liquid fuel (oil), into a combustible synthesis gas, composed primarily of carbon monoxide and hydrogen (Figure B17). This gas can subsequently be used to produce steam, which is a focus of this section, or generate power, or synthesize a variety of chemical products such as hydrogen, methanol or synthetic natural gas.

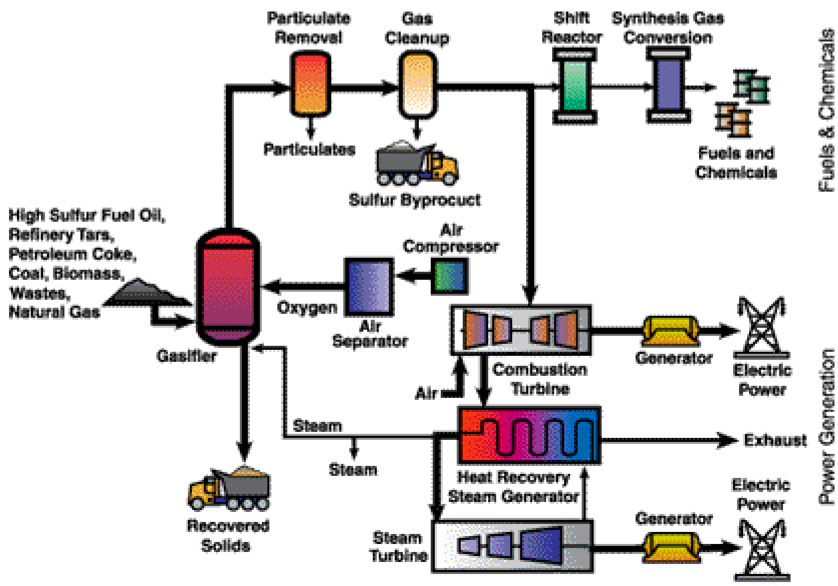



Figure B17. Coal Gasification process.

The process of coal gasification in a surface gasifier can be replicated underground by drilling into the hydrocarbon reserves, injecting air or oxygen, and gasifying the in-seam coal seam. The product gases are transported to the surface for processing and utilization (power generation, industrial heating or as chemical feedstock).

### Technology Characteristics

The technology is still being developed. Its significant drawbacks are the 20-25 percent efficiency penalty for conversion to a gas with no subsequent gain in the overall conversion to steam and electricity and a substantial investment in equipment to gasify coal and clean the gas.

In addition, the following issues should be addressed when considering employing the coal gasification technology and selecting the site.

### Technology Maturity

Gasification has been in commercial use for more than fifty years as a process technology for the refining, chemical, and power industries.

### Size

A coal gasification facility size is site specific and varies based on the resource availability and its depth. For example, two existing fields (Yuzhno-

Abinsk, Siberia, and Angre, Uzbekistan), each gasify in the region of 350,000 – 500,000 tons of coal per year at a depth of 130-350 meters.

The total daily world capacity of the coal gasification facilities when in operation will be just under 430 million normal cubic meters of synthesis gas. This is the energy equivalent of more than 770,000 barrels of oil per day. [Note: one million normal cubic meter of syngas is the equivalent of 37.3 million standard cu ft, or 10.4 billion Btus.]

### Using Coal Gasification in Alaska

Although coal gasification in Alaska is technically feasible, there are concerns about the ability to provide a clean fuel reliably and efficiently.

### Permitting

The coal gasification plant will need to meet all the necessary environmental requirements of process and power plant. Detailed environmental impact assessments will be required.

Given a lack of applicability of coal gasification in interior Alaska, a more in-depth discussion of permitting issues is not warranted.

### Benefits

- Gasification adds value to produce marketable fuels and products. It can be used to extract energy from seams too deep for conventional mining.
- High efficiency power generation in gas turbines.

### Disadvantages

- There is a 20-25 percent efficiency loss in conversion to gas.
- There is a substantial investment in equipment to gasify coal and cleanup the gas.
- The environmental considerations are significant.

### Conclusion

The technology is still being developed, and at its current development stage, it is not cost-effective and it is not reliable.

## Pressurized Fluid Bed Combustion

### Technology Description

Fluid Bed Combustion (FBC) technology was developed by the oil industry during the 1930s and the principles have been applied to the controlled combustion of solid fuels since the 1960s.

When a gas is passed upwards through a bed of fine particles, the degree of disturbance is determined by the velocity of the gas. At low velocities there is very little particle movement, but as the velocity increases, individual particles begin to be forced upwards until they reach the point at which they remain suspended in the gas stream. Any further increase in gas velocity causes turbulence, with rapid mixing of the particles. A particle bed in this state behaves like a liquid and can be described as "fluidized."

Fluidized bed coal combustion uses a continuous stream of combustion air to create the necessary turbulence. The constant mixing of particles encourages complete combustion and also allows a uniform temperature to be maintained within the combustion zone. The ash produced accumulates in the bed, eventually forming the bulk of the particles. Surplus ash is drawn off at intervals to maintain the bed at the correct level. Most of the heat generated is transferred to a water/steam system, usually via water tubes immersed in the bed.

FBC technologies (Figure B18) fall into one of two main categories:

- atmospheric-pressure
- pressurized.

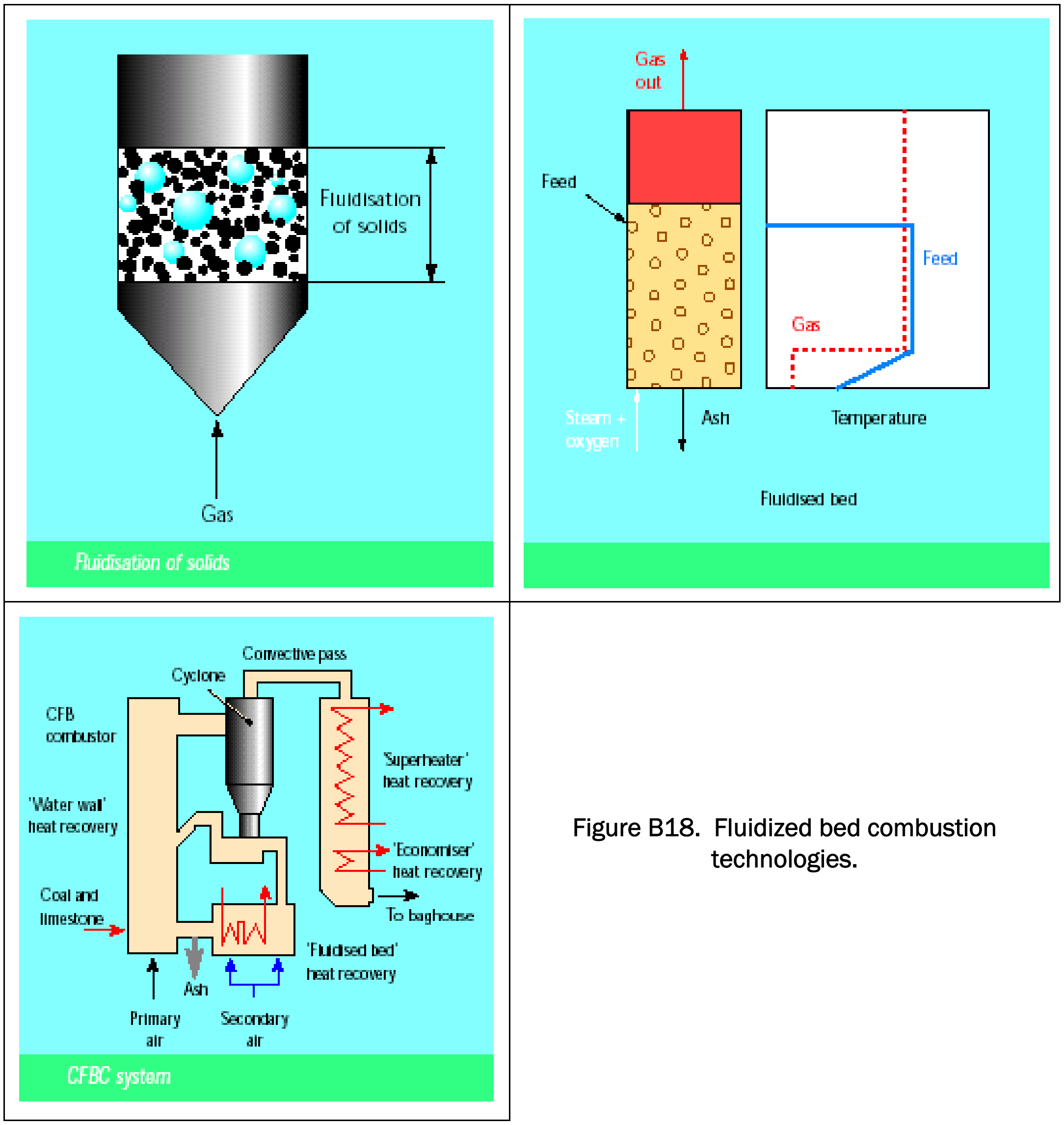



Figure B18. Fluidized bed combustion technologies.

Atmospheric-pressure FBCs (AFBCs) are commercially available as either bubbling bed or circulating bed systems (see the picture below that shows a circulating fluid bed combustor (CFBC)). Several hundred examples of both types are operational in industrialized countries with over 2500 (mostly bubbling beds) operating in China and India together. AFBCs have been demonstrated in coal-fired power generation units of up to about 250MWe and designs are believed to be available for up to 500-600MWe.

Pressurized FBCs (PFBCs) operates at high pressures and, therefore, can be more compact than AFBC. It can run exhaust heat through the turbines as well as the steam cycle. The PFBC also may produce more electricity for a given amount of fuel.

The gas generated by PFBC units can be expanded through a gas turbine to generate additional electricity. In combined cycle power applications, 75–80 percent of the electricity is generated using a conventional steam turbine generator. The gases leaving the combustor are, however, under pressure. After a cleaning process that uses high-efficiency cyclones or high-temperature filters to remove solids from the gas stream, these gases can be expanded through a gas turbine set to generate electricity. This form of combined cycle application can technically increase the thermal efficiency of the process to 42–45 percent.

Exhaust gas from the turbine can additionally be used in a steam generator to produce steam for a steam turbine. The approach is not subject to the same maximum temperature limitations as conventional combustion technologies and can therefore take full advantage of the higher efficiencies offered by raising the inlet temperature to the gas turbine.

### Technology Characteristics

There are many different gasification processes. There are three main types, classified by flow regime, that is, the way in which the fuel and oxidant flow through the gasifier. They are entrained flow, fluidized bed, and moving (or fixed) bed. All three types can be used to gasify coal and gasifier selection will depend on coal characteristics (for example, reactivity, ash content and melting point) and the size of plant (Table B7).

Table B7. Coal gasifier types.

*Comparison of gasifier types*

| | Entrained flow | Fluidised bed | Moving bed |
|---|---|---|---|
| Fuel type | Solid and Liquid | Solid | Solid |
| Fuel size (solid) | <500µm | 0.5-5mm | 5-50mm |
| Residence time | 1-10s | 5-50s | 15-30min |
| Gas outlet temperature | 900-1400°C | 700-900°C | 400-500°C |

In a fluidized bed, solids are suspended in an upward-flowing gas stream (the oxidant). Like the FBC, the fuel ash must not be allowed to become so hot that it melts and sticks together. If the fuel particles stick together, the bed will defluidize. Air is therefore commonly used as the oxidant to keep the temperature below ~1000 °C.

The advantages of fluidized bed gasifiers include the ability to accept a wide range of solid feeds including household waste (suitably pre-treated) and biomass such as wood. They are also to be preferred for very high-ash coals, particularly those in which the ash has a high melting point.

### Technology Maturity

R&D into “directly-fired” gas turbine schemes, as described above, is being undertaken in the United States and Germany; however, adequate cleaning of very high-temperature combustion gases, prior to use in the gas turbine, has yet to be demonstrated.

Although PFBC technology moves coal combustion to a new plateau of performance with expected efficiencies for initial systems approaching 45 percent, and reduced $SO_2$ and NOx emissions, the research shows that PFBC technology has yet to be successfully demonstrated. As of today, it continues being a complex and expensive technology.

### Technology Applications

The first commercial application of PFBC technology was at Värtan in Sweden; the 135MWe/224MWth plant provides both electricity and district heating from a city center site where space is at a premium and environmental restrictions are particularly stringent.

Other operational plants include Escatron (80MWe) in Spain, and Wakamatsu (71MWe) and Tomato-Atsuma (80MWe) in Japan.

These seem to be among the very few PFBC installations that currently operate in the world.

### Size

PFBC sizes commercially installed vary from 70-MW to 150-MW.

### Using PFBC Technology in Interior Alaska

Because of a lack of successful PFBC demonstrations in the United States, including the Alaska region, using the technology in Alaska appears to be premature.

### Permitting

Given a lack of PFBC applicability in Fairbanks, a more in-depth discussion of permitting issues is not warranted.

### Benefits

Technically, PFBC offers a number of advantages over conventional combustion systems:

- The bed can be operated at temperatures (>~900 °C) above which ash melts and forms slag
- The scrubbing action of the moving particles on the immersed water tubes increases the rate of heat transfer
- The bed has a substantial thermal capacity which allows a variety of fuels to be burnt, including poor-quality fuels with a high level of unwanted mineral matter or moisture content as well as mixed fuels
- NOx formation is reduced because operating temperatures are low and the system offers opportunities for air staging adding a suitable sorbent, such as crushed limestone.
- Ensures that up to 90 percent of any $SO_2$` released during combustion can be retained in the bed as a sulphate.

### Disadvantages

Despite the above potential benefits, the PFBC technology has more serious technical obstacles to overcome.

- PFBC is less well developed than other technologies, such as AFBC.
- Gas clean-up, which is performed at elevated temperatures to improve combustion efficiency, requires high removal rates of contaminants. Demonstration scale units have shown need for improvement in gas clean-up technologies to reduce the apparent corrosion of gas turbine blades. This is a primary concern for combined cycle PFBCs.
- Commercial availability of PFBC technology is still contingent on successful presentation. It is unlikely that sufficient number of PFBC

commercial units could be completed and operating within next decade, although the PFBC's longer-term potential is quite promising.

### Conclusion

Pressurized Fluid Bed Combustion (PFBC) is a developing technology for cleaner and more efficient production of power from coal. Demonstration scale unit have shown need for improvement in gas clean-up technologies to allow reliable commercial use of the technology. Larger scale plants than those involved in this study are necessary for economic application of PFBC. At its current development stage, PFBC is not considered attractive for consideration in this study.

## Coal Bed Methane (CBM)

### Technology Description

Methane usage is viewed today as a solution to the green house gas (GHG) emission problem associated with fossil fuel use. Methane occurs naturally as natural gas, gas hydrates, and as coal-bed methane. It is produced by bacterial action at waste landfill sites, and can be generated through underground (or gasifier) coal gasification (plus methanation). It can also be liquefied to facilitate transport.

Coal-bed methane (CBM) extraction (Figure B19) is now being used to recover useful energy from coal mining operations and to reduce emissions of methane, whilst also improving safety.

Virtually all coals contain some methane, which results from the original coalification process. As a general rule, this methane content increases with depth and with coal rank. Part of the methane is released when the coal is mined, which can be dangerous. There are a number of ways of reducing this problem. One is to pre-drain the methane by drilling vertical holes from the surface. This led to the concept of using this gas as a source of energy, independently of any mining operation.

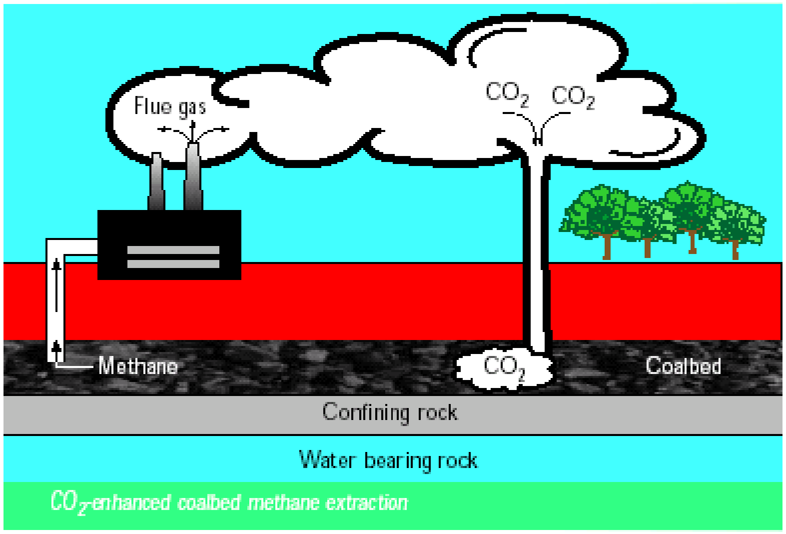



Figure B19. Coal bed methane extraction.

The gas is filtered to remove any salts and then passes through a water slug catchment unit. From there, the flow of gas goes to compressors, which incorporate water extraction, and the water is disposed. The pressurized gas then passes into a glycol dehydrator. This counter-current column is interconnected to a re-boiler to remove water from the glycol; again, the water is forwarded to the central collection facility. The de-watered and pressurized gas is then ready use.

CBM extraction is a way of obtaining useful energy, but is not equivalent to actually mining the coal. Nevertheless, it provides a means of extracting some energy from coal seams that cannot be mined.

## Technology Characteristics

Typical CBM gas has a heating value is in the range of 950 to 1,110 Btus per cubic foot. The gas does not contain any appreciable hydrogen sulfide. $CO_2$ knock-out may be required on some resources (see picture above), however, this is site specific. Also, water quantity and hence de-watering needs are site specific. There is no known $H_2S$ in any U.S. CBM, and $CO_2$ is generally less than 2 percent of the total gas volume.

Depending on the vertical cracking (cleat) characteristics of the coal and the methane release pathway, the methane release potential of various seams may need to be improved by pressurizing and fracturing the coal body. In this case, a simple reciprocating well pump would be located at the well. Both methane and water are pumped to the surface and sepa-

rated. Depending on the coal characteristics, the number of wells installed depends on the flow required; approximately, one well every 250 acres.

### Natural Resource

Abundant coal resources exist in interior Alaska. Whether or not CBM can be developed into an environmentally acceptable and economic source of fuel is unknown.

### Technology Maturity

This technology is furthest advanced in the United States where over 5,000 wells are producing nearly 700 million cu ft of gas per year—equivalent to about 23 million tons of coal or 15 million tons of oil. However, CBM development is known for its major geo-technical barriers such as low permeability of coal, variable or low quality gas, and variation in gas supply. In addition, total energy content of the gas produced today will not normally exceed 1 percent of the host coal. Also, significant environmental issues discussed below hinder CBM development. The U.S. Supreme Court recently refused to review a lower court decision that water from CBM activities is a pollutant and is subject to regulation.

Experience in other countries has been even less encouraging, generally because their coals have low permeability compared with those in the two main CBM-producing basins in the United States.

### Size

A typical CBM well could be down to 1,000 meters or so in depth and would bore through many coal seams.

### Potential Interior Alaska Installation

"In CBM developments in the Lower 48, people legitimately fear for their clean water wells and private property, which can be severely disturbed by roads, pipelines, drilling rigs, noisy compressors, truck traffic and the general unpleasantness of industrial activity nearby. For surface property owners, the costs greatly outweigh the benefit. " Robin McLean of Alaska Center for the Environment, Daily News Letters, August 2003. He continues: "Unregulated coal bed methane development is irresponsible. A moratorium should be placed on CBM development in Alaska until a sound set of regulatory guidelines can be implemented to avoid the disasters of CBM development in the Lower 48."

Given this level of environmental concern and that this technology is still undergoing the development, it should not be regarded as a proven, viable technology.

### Permitting

At the Federal level, the National Environmental Protection Act (NEPA) often causes actions to be reviewed for their cumulative impacts. As of today, NEPA has not yet applied in Alaska.

### Benefits

CBM technology provides a means of extracting some energy from coal seams that can not be mined.

### Disadvantages

- The total energy content of the gas will not normally exceed 1 percent of that of the host coal.
- CBM technology must be further developed before it can be used cost-effectively and in a reliable fashion.
- CBM development might have to compete with pipeline gas in the Fairbanks area.
- Underground coal fires are reported to have been a problem. De-watering of the coal beds caused by the extraction of produced water is often blamed. The fires can heat the overlying soil to the degree that vegetation is killed.
- Produced water is the water pumped from the aquifers associated with coal beds. The aquifer must be pumped out ("produced") to cause coal beds to release methane gas. This produced water is a major environmental concern.

### Conclusion

CBM provides a possible means to exploit a coal resource in areas where the coal is unlikely to be mined using traditional mining methods. However, major geo-technical barriers such as low permeability of coal, variable or low quality gas, and variation in gas supply and significant environmental issues rule out consideration of CBM as a viable fuel supply for this study.

# Appendix C: Capital Cost Estimates and Basis of Estimates

TECHNICAL MEMORANDUM

## Basis for Cost Estimate Development—Greater Fairbanks Military Complex Energy Study

PREPARED BY: R. J. Witherell

DATE: 26 March 2004

REVISION: 6

## 1.0 Purpose

The purpose is to provide order-of-magnitude capital cost estimates for the following alternative solutions for addressing the future energy needs for the Greater Fairbanks Military Complex, which includes Fort Wainwright, Eielson Air Force Base, and Fort Greely, all of which are located in the Fairbanks, AK, vicinity. The various alternative solutions are presented for the Fort Wainwright and Eielson Air Force Base locations plus four different regional solutions incorporating a central plant concept. Estimates of this type are expected to be accurate within plus 50 percent to minus 30 percent of the estimated cost.

## 2.0 Scope

### 2.1 Fort Wainwright

The plant currently consists of five steam-turbine generators (one 5 MW backpressure, one 5 MW which has been abandoned in place and three 5 MW condensing units, for a total of 20 MW) supported by six 150,000 lb/hr. coal fired steam-water tube boilers. There are also two boilers #1 and #2 which have been abandoned in place. Each operating boiler is equipped with a bag house (currently being installed) to provide for air pollution control. Coal is delivered by rail and is gravity fed to each boiler from six coal bunkers. The cooling cycle utilizes a cooling pond located adjacent to the plant.

### 2.1.1 Alternative 1 – Repair: No Added Capacity

No capital cost estimate was required for this alternative.

### 2.1.2 Alternative 2 – Repair and Upgrade

The Scope of this alternative includes the removal of existing Units 1 and 2 Steam Turbine Generators and associated pedestals and foundations. After removal, the scope includes the replacement of these two machines with two new 16 MW condensing Steam Turbine Generators with associated pedestals and foundations utilizing a new Air Cooled Condenser for cooling purposes. These units will be in close proximity for interfacing with existing plant services including steam headers, cooling water, air, etc. and will easily fit within the footprints of the older machines being replaced. Costs for retrofitting a dry scrubber and SCR for each boiler was included due to environmental requirements.

Construction operations for this alternative will require a high degree of difficulty and loss of labor productivity due to very tight work areas, difficult positioning of construction equipment, the necessity for a remote laydown area which will require double handling of materials (refer to labor section below). A labor factor of 1.79 was used in the estimate preparation for this alternative.

### 2.1.3 Alternative 3 – Repair: Electricity Produced by Following the Heat Demand

No capital cost estimate was required for the alternative.

### 2.1.4 Alternative 4 – Upgrade with New Fluidized-Bed Combustion Boilers and Additional Steam Turbine-Generators

No capital cost estimate was required for this alternative because it is not a recommended option.

### 2.1.5 Alternative 5 – New Plant Using Circulating Fluidized-Bed Combustion Boilers

This alternative includes the construction of a new plant consisting of four 180,000 lb/hr Circulating Fluidized–bed Combustion Boilers each with SNCR and baghouse for pollution control, Boiler Feed Pumps, Condensate System, three 15 MW Condensing Steam Turbine Generators, Air Cooled Condenser, railspur extension, Coal Handling, Limestone Handling and

ash removal equipment, enclosure building, turbine bay crane, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil. Two miles of Utilidor were included.

#### 2.1.6 Alternative 6 – Combustion Turbine Cogeneration (HRSG for Heat): Liquid Fuel

This alternative includes the construction of a new plant utilizing three oil-fired Solar Titan 130 Combustion Turbine Generators rated at 13.5 MW, three single pressure Heat Recovery Steam Generators duct-fired to 120,000 lb/hr and one oil-fired 120,000 lb/hr package boiler to cover the HRSG n-1 condition. The scope includes an enclosure building, SCRs, CO Reactors, oil delivery, transfer and storage facilities, associated balance of plant equipment, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil. Two miles of Utilidor were included.

### 2.2 Eielson Air Force Base

The plant currently consists of five steam-turbine generators (one 10 MW condensing, two 5 MW condensing and two 2.5 MW backpressure units, for a total of 25 MW) supported by six 120,000 lb/hr coal-fired steam-water tube boilers. Each boiler is equipped with a side stream bag house to provide for air pollution control. There is a current project in progress installing full flow bag houses. Coal is delivered by rail and is gravity fed to each boiler from six 200 ton coal bunkers. The cooling cycle utilizes a 24 acre 20 foot deep cooling pond located adjacent to the plant and wells. Summer operation uses the well water with discharge to the cooling pond. Winter operation uses the cooling pond. Four hundred pounds of 650 degree steam is used to turn the steam-turbine generators. 100 lb steam is distributed through 26.28 miles of utilidors to heat the base. The plant also has 8.5 MW of backup diesel generators (one EMD rated at 2,500 kW and four Cummins/Onans rated at 1,500 kW each).

#### 2.2.1 Alternative 1 – Repair: No Added Capacity

No capital cost estimate was required for this alternative.

### 2.2.2 Alternative 2 – Repair and Upgrade

The scope of this alternative includes the construction of a building addition, installation of a new 10 MW condensing Steam Turbine Generator with associated mat foundation utilizing an Air Cooled Condenser for cooling purposes. This unit will be in close proximity for interfacing with existing plant services including steam headers, cooling water, air, etc. Costs for retrofitting a dry scrubber and SCR for each boiler was included due to environmental requirements.

Construction operations for this alternative will require a high degree of difficulty and loss of labor productivity due to very tight work areas, difficult positioning of construction equipment, the necessity for a remote laydown area which will require double handling of materials (refer to labor section below). A labor factor of 1.79 was used in the estimate preparation for this alternative.

### 2.2.3 Alternative 3 – Repair: Electricity Produced by Following the Heat Demand

No capital cost estimate was required for the alternative.

### 2.2.4 Alternative 4 – Upgrade with New Fluidized-Bed Combustion Boilers and Additional Steam Turbine-Generators

This alternative includes the construction of a new plant extension to the existing building, adding two new 120,000 lb/hr Circulating Fluidized–bed Combustion Boilers each with SNCR and baghouse for pollution control, Boiler Feed Pumps, Condensate System, one 20 MW Condensing Steam Turbine Generator, Air Cooled Condenser, Coal Handling, Limestone Handling and ash removal equipment, turbine bay crane rail extension, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil.

### 2.2.5 Alternative 5 – New Plant Using Circulating Fluidized-Bed Combustion Boilers

This alternative includes the construction of a new plant consisting of four 160,000 lb/hr Circulating Fluidized–bed Combustion Boilers each with SNCR and baghouse for pollution control, Boiler Feed Pumps, Condensate System, three 12 MW Condensing Steam Turbine Generators, Air Cooled Condenser, railspur extension, Coal Handling, Limestone Handling and

ash removal equipment, enclosure building, turbine bay crane, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil. Two miles of Utilidor were included.

### 2.2.6 Alternative 6 – Combustion Turbine Cogeneration (HRSG for Heat): Liquid Fuel

This alternative includes the construction of a new plant utilizing three oil-fired Solar Mars 100 Combustion Turbine Generators rated at 10 MW, three single pressure Heat Recovery Steam Generators duct-fired to 106,000 lbs/hr and one oil-fired 106,000 lb/hr package boiler to cover the HRSG n-1 condition. The scope includes an enclosure building, SCRs, CO Reactors, Air Cooled Condenser, oil delivery, transfer and storage facilities, associated balance of plant equipment, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil. Two miles of Utilidor were included.

## 2.3 Regional

This option is based on meeting the peak electrical demands for all the facilities; Fort Wainwright, Eielson Air Force Base, Fort Greely (including the Cold Region Test Center feed), and Missile Defense Agency.

The plant would be located between Fort Wainwright and Eielson Air Force Base. A specific location has not been selected for this analysis, but preferable attributes would include being near the existing railroad (for the coal-fired alternatives), transmission lines in close proximity, having available water, and outside the CO non-attainment zone. The sizing basis will consider the individual electric peaks being concurrent and allow 10 percent of the gross generation for auxiliary power. Since most of the electrical demand would be Wainwright and Eielson, no allowance is included for transmission losses. For alternatives 1 & 2, the heating demand at each facility will be supplied by the existing plants, following the “heat curve” for Wainwright and Eielson.

### 2.3.1 Alternative 1 – Coal-Fired Power Generation Only

This alternative includes the construction of a new plant consisting of four 270,000 lb/hr Circulating Fluidized–bed Combustion Boilers each with SNCR and baghouse for pollution control, Boiler Feed Pumps, Condensate System, four 27 MW Condensing Steam Turbine Generators, Air Cooled Condenser, 2 mile railspur extension, Coal Handling, Limestone Handling and ash removal equipment, enclosure building, turbine bay crane, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil.

### 2.3.2 Alternative 2 – Oil-Fired Power Generation Only

This alternative includes the construction of a new combined cycle (CC) plant utilizing four oil-fired General Electric LM2500 aeroderivative Combustion Turbine Generators rated at 23.9 MW, four single pressure 53--,000 lbs/hr Heat Recovery Steam Generators and four 6.5 MW condensing Steam Turbine Generators. The scope includes an enclosure building, SCRs, CO Reactors, Air Cooled Condenser, oil delivery, transfer and storage facilities, associated balance of plant equipment, and switchyard interface into the existing grid. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil.

### 2.3.3 Alternative 3 – Coal-Fired CHPP with Long-Distance Heat Transmission

This alternative includes the construction of a new plant consisting of four 515,000 lb/hr Circulating Fluidized–bed Combustion Boilers each with SNCR and baghouse for pollution control, Boiler Feed Pumps, Condensate System, four 35 MW Condensing Steam Turbine Generators, Air Cooled Condenser, 2 mile railspur extension, Coal Handling, Limestone Handling and ash removal equipment, enclosure building, turbine bay crane, and switchyard interface into the existing grid. Heat will be transferred via hot water through a long distance heat transmission pipeline 25 miles in length. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil.

### 2.3.4 Alternative 4 – Oil-Fired CHPP with Long-Distance Heat Transmission

This alternative includes the construction of a new open cycle (OC) plant utilizing four oil-fired General Electric LM2500+ aeroderivative Combustion Turbine Generators rated at 28 MW, and five single pressure 247--,000 lbs/hr (duct-fired) Heat Recovery Steam Generators. The scope includes an enclosure building, SCRs, CO Reactors, Air Cooled Condenser, oil delivery, a 247,000 lb/hr auxiliary boiler, transfer and storage facilities, associated balance of plant equipment, and switchyard interface into the existing grid. Heat will be transferred via hot water through a long distance heat transmission pipeline 25 miles in length. Piling was included as a foundation system for seismic conditions and an allowance was included for dewatering and shoring that may be required for wet and unstable soil.

## 2.4 Eielson Existing Plant Decommissioning

The existing Eielson Plant was chosen as typical of either Eielson or the Fort Wainwright sites for the purposes of calculating the costs associated with decommissioning and demolition that may be required in such case where new facilities will provide replacement power and heat requirements allowing for the retirement of the older facility.

Quantities to be removed were derived based on an in-house estimating model for this plant configuration. The scope of work includes demolition and removal of the existing plant to 6 in. below finish grade, removal of all material, salvage of major equipment pieces, salvage for steel and copper materials and final landscaping consisting of reseeding of all areas affected by the plant construction.

Demolition unit rates were based on in-house and published estimated data. Salvage credits costs for steel and copper were derived from 2003 R.S. Means Construction Cost Data. Salvage values for the major equipment items were calculated as follows for each year for 30 years:

| | | |
|---|---|---|
| STGs: | Usage Factor: | 2.2 percent |
| | Technology Loss: | 2.2 percent |
| | Heat Rate Loss: | 2.0 percent |
| Boilers: | Usage Factor: | 7.0 percent |
| Other Equipment: | Usage Factor: | 6.0 percent |

Asbestos removal was included as an allowance assuming 96,000 SF of removal located in and around the existing boilers and associated piping insulation.

## 3.0 Construction Approach

The estimates are based on a direct-hire merit shop craft labor approach utilizing specialty contractors for the following:

Site Earthwork
Railroad Work
Painting
Insulation
Long Distance Heat Transfer Pipeline

## 4.0 Estimating Methodology

The Combustion Turbine estimates were developed utilizing equipment prices and installation rates which were based on man-hour rates and costs derived from in-house estimating program model and database information. Pricing for major equipment was obtained from published information such as Gas Turbine World 2003 GTW Handbook and from telephone and written quotes from manufacturers. Freight was included for shipping from L-48 to the Fairbanks area for major pieces of equipment.

The CFB Boiler Alternatives were developed utilizing an in-house estimating program model and manufacturer's quotes obtained for this and other recent projects for the pricing basis for the major power block equipment. Where the exact capacities were not matched, the equipment pricing was adjusted for the capacities proscribed for each individual alternative. Freight was included for shipping from L-48 to the Fairbanks area for major pieces of equipment. The manufacturers pricing was sourced from Table C1.

Table C1. Source of manufacturers pricing.

| Item | Manufacturer | Obtained for |
|---|---|---|
| CFB Boilers | Foster Wheeler | This Project |
| STGs | Shin Nippon | Previous Project |
| Air Cooled Condenser | Marley Cooling Tech. | Previous Project |

## 5.0 Labor

All craft labor rate will be based on Davis-Bacon published rates dated June 2003 for this area. It will be assumed that these sites will be Open shop labor allowing union or non-union participation. Craft rates were built-up to include the base rate, fringes, legalities and applicable Workmen Compensation percentages including an experience factor assump-

tion. These individual rates have been incorporated into crews required for each major construction element and include Foreman and General Foreman rates.

A Craft Labor Factor (labor productivity) of 1.22 has been calculated based on area labor craft productivity for late spring, summer and early fall. This is assuming that during this relatively good weather period, craft would be working 60 hour weeks. For the late fall, winter and early spring months, a labor factor of 1.13 was calculated assuming 50 hour weeks and predominately inside work would be performed. For these project alternatives with durations projected to be 12 months or greater (all alternatives fall into this category) an average labor factor of 1.23 was used.

In areas where demolition of existing structures is required and where congestion exists, further evaluation of labor productivity was performed to factor in the amount of overtime required, the amount of outside work required during cold weather, extent of site paving, proximity of laydown area and craft parking, amount of high work required, degree of congestion in the work area and the amount and difficulty of demolition required.

## 6.0 Schedule

All estimates for each alternative have been prepared assuming a 50 or 60 hour work week as described under the labor section above.

## 7.0 Escalation

No escalation was included.

## 8.0 Home Office Engineering Services

Engineering cost was calculated based on historical data derived from similar recently completed projects.

## 9.0 Construction Indirects

Includes costs for Field Staff, Temporary Facilities, Construction Equipment and small tools/consumables, Start-up Engineering, Start-up Craft Assistance and Heavy Hauling.

## 10.0 Contractor's Contingency

A 15 percent contingency was included for each of the estimates except Fort Wainwright Alternative 2, Eielson Air Force base Alternative 2 and Eielson Air Force base decommissioning for which a 20 percent contingency percentage was used.

## 11.0 Contractor's Fee

An 8 percent fee was applied to the total installed costs.

## 12.0 Inclusions

- Structural and civil works to the site battery limits except for Utilidors where noted
- Mechanical and plant equipment
- Piling
- Bulks
- Contractor's construction supervision
- Temporary facilities
- Construction power and water
- Construction equipment, small tools and consumables
- Start-up spare parts and start-up craft labor
- First fills
- Contractor's Contingency and Fee
- PL & PD Insurance
- Performance and Payment Bond Cost

## 13.0 Exclusions

- Soils remediation
- All insurances except PL & PD including delay in start-up insurance
- Land, land rights or acquisitions
- Operating spare parts
- Project Financing
- Plant Licenses or environmental permits
- Rolling stock, operations maintenance equipment
- Removal or relocation of existing facilities or structures (except as noted otherwise)
- Taxes
- Landscaping
- Sales Tax
- Fuel And Water costs used during startup

## 14.0 Assumptions and Qualifications

- All excavated soil will be disposed of elsewhere on sites.
- The sites do not contain any EPA defined hazardous or toxic wastes or any archaeological finds that would interrupt or delay the project.
- Equipment is supplied with manufacturers standard paint except for the HRSGs which require painting. Otherwise, only field touch-up painting will be required.
- All exterior steel pipe racks will be galvanized.
- Craft parking is immediately adjacent to the sites on a existing lot.
- Craft bussing is not required.
- Rock excavation is not required.
- A construction or operating camp has not been included.
- An ample supply of skilled craft is available within the vicinity of the sites.
- The sites have free and clear access with adequate laydown area immediately adjacent.
- Enclosed plants are assumed.
- No site requirements that would impose unreasonable site sound requirements during the construction period.

## 15.0 Interconnects

ROADS: Battery Limit
WATER: Battery Limit
WASTEWATER: Battery Limit
ELECTRIC: Battery Limit

## 16.0 Switchyard

Fort Wainwright and Eielson Air Force base alternatives which require increased purchases from GVEA will require interconnect upgrade in terms of GVEA a standard transformer configuration of 12/16/20MVA multiples based on the MVA requirement projected. The value assumed for this 20 MVA multiple is $4.3 million each. Therefore, in addition to the capital cost requirements stated, the following values will be added based on the projected GVEA tie-in needs in multiples of 20 MVA:

Fort Wainwright:

| | Projected | Cost |
|---|---|---|
| ALTERNATIVE 1: | 33.6875 MVA | $8.6 Million |
| ALTERNATIVE 2: | 20 MVA | $4.3 Million |

| | | |
|---|---|---|
| ALTERNATIVE 3: | 32.82 MVA | $8.6 Million |
| ALTERNATIVE 4: | Not Considered | |
| ALTERNATIVE 5: | 18.75 MVA | $4.3 Million |
| ALTERNATIVE 6: | 16.875 MVA | $4.3 Million |

Eielson Air Force Base:

| | Projected | Cost |
|---|---|---|
| ALTERNATIVE 1: | 13.6875 MVA | $4.3 Million |
| ALTERNATIVE 2: | 12.5 MVA | $4.3 Million |
| ALTERNATIVE 3: | 24 MVA | $8.6 Million |
| ALTERNATIVE 4: | 25 MVA | $8.6 Million |
| ALTERNATIVE 5: | 15 MVA | $4.3 Million |
| ALTERNATIVE 6: | 13 MVA | $4.3 Million |

The regional alternatives assume, in each instance, a switchyard with a 138 kV ring bus configuration.

## 17.0 Sales Tax

Excluded.

## 18.0 Environmental Permits

Table C2 summarizes the cost for environmental permits.

Table C2. Cost for environmental permits

| Location | Permit Cost |
|---|---|
| Fort Wainwright: | $ 750,000 |
| Eielson Air Force Base: | $1,500,000 |
| Regional: | $1,500,000 |

## 19.0 Land Costs

An amount of $150,000 was included for each Regional ALTERNATIVE for land costs.

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This study evaluated onsite and regional options for providing heat and power to Fort Wainwright, Eielson Air Force Base, Fort Greely, and the Ground-Based Midcourse Defense installation adjacent to Fort Greely, collectively known as the Greater Fairbanks Military Complex (GFMC). The alternatives evaluated include site-specific alternatives (continued operation of existing plant and new plant) and regional alternatives to provide power or both heat and power. The report provides background information on the energy supply situation in Interior Alaska, the availability of fuels, and the existing energy infrastructure and reviews the suitability of possible technologies for long-term heat and power solutions for the GFMC installations. The report also develops evaluation criteria for fuels and alternative heat and power solutions. Life-cycle costs are developed for each alternative and are used in the evaluation along with other criteria such as security, impact on Alaska infrastructure, and air and water quality. Results of the analysis are presented to allow the Department of Defense to make an informed decision about heat and power solutions for the installations.

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